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Santarella & Eckert, LLC
7050 Puma Trail
Littleton, CO 80125
303-932-7610
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FAX COVER SHEET

FAX NUMBER TRANSMITTED TO: 303-312-6953

To: Jim Eppers
Of: US EPA Region 8 ENF-LEP
From: Joseph M. Santarella Jr.
Client/Matter: RMELC/Xcel Comanche
Date: April 15, 2005

DOCUMENTS	NUMBER OF PAGES*
NPS Comments	25
CH2MHill Response	13
APCD Response	7

COMMENTS:

Dear Jim - Per our telecom, I am transmitting the correspondence between NPS, CH2MHill and APCD regarding the implications of the EPA NOV issued to Xcel Energy for NSR violations at Comanche Station. Specific discussion regarding the EPA NOV may be found in the NPS comments at 1-5 in the narrative attachment, the CH2MHill response at 3, and the APCD response at 3. Let me know if you have any questions or if I may be of assistance.

Kindest regards,

Joe

Joe Santarella

2nd Transmittal
Jme

P.S. I am sending the documents in two separate transmissions due to size.

* NOT COUNTING COVER SHEET. IF YOU DO NOT RECEIVE ALL PAGES, PLEASE TELEPHONE US IMMEDIATELY AT 303-932-7610.

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Englewood, CO 80112
Tel 303.771.0900
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CH2MHILL

January 6, 2004

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BY FEDERAL EXPRESS

Ms. Jackie Joyce
Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 Cherry Creek Dr. S
Denver, Colorado 80246-1530

Re: Public Service Company of Colorado's Permit to Construct Comanche Station Unit 3: Response to November 24, 2004, Comments by the National Park Service

Dear Ms. Joyce:

We write on behalf of Public Service Company of Colorado ("PSCo") in response to the draft comments filed with the Air Pollution Control Division (APCD) by Liana Reilly of the National Park Service ("NPS") on November 24, 2004, regarding the PSCo Clean Air Act permit application referenced above.

The NPS comments may fairly be divided into five areas: (1) the impact of future BART requirements on the creditability of contemporaneous net emissions decreases from Comanche Units 1 and 2; (2) the impact of EPA's current PSD enforcement efforts on the creditability of contemporaneous net emissions decreases from Comanche Units 1 and 2; (3) the impact of heat inputs to Comanche Units 1 and 2 in excess of Title V limits on the creditability of contemporaneous net emissions decreases from those units; (4) the results of PSCo's top-down BACT analysis; and (5) the results of PSCo's modeling for pollutants for which a significant net emissions increase is predicted. Our responses to each of these five issues—as well as your related comments shared with us during our meeting on December 21, 2004, and the letter dated December 13, 2004, from Chuck Machovec to James Nall—are set forth below.

PSCo disagrees with NPS's arguments and legal assertions and addresses their points in detail below. Nonetheless, it is important to note that since NPS sent their draft comments on November 24, 2004, Public Service Company of Colorado entered into a Settlement Agreement with a broad coalition of citizen and environmental organizations. The Settlement Agreement is dated December 3, 2004, and has previously been sent to you. The terms of the Settlement Agreement should fully address the NPS comments and concerns.

1. Potential future reductions under BART do not render current emissions decreases non-creditable for PSD permitting purposes

The NPS comments suggest that future potential BART reductions at Comanche Units 1 and 2 render the emission reductions at those units non-creditable for netting purposes. We disagree. EPA's PSD regulation plainly states that an emissions decrease is creditable when "the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions."[1] Because BART requirements are not currently applicable to Comanche Units 1 or 2—and may very well not become applicable until as late as January 31, 2013—the current permits for those units do not include BART-related limitations on either actual or allowable emissions. In fact, the very provisions of EPA's New Source Review Workshop Manual cited by NPS in its comments actually confirm that emissions decreases are calculated on the basis of *current* limitations on actual or allowable emissions, and *not* potential *future* limitations.[2] The NPS comments appear to confuse those emission limits that are currently applicable to a source, and those emission limits that may at some time in the future become applicable to the source—even if implementation of the future potential limitations is a decade in the future. This view of PSD netting is at odds with the plain text of the regulation and the primary guidance document on the point, and should not form the basis for a permitting decision by Colorado.

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1 40 C.F.R. § 52.21(b)(3)(vi)(*a*).

2 *See* NPS Comments at 3 (citing "New Source Review Workshop Manual (Draft)," at A.41 (Envt'l Prot. Agency, Oct. 1990) [hereinafter "Workshop Manual"]) ("For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels.").

2. Potential future reductions resulting from EPA's nascent NSR enforcement action do not render current emissions decreases non-creditable for PSD permitting purposes

The NPS comments also suggest that EPA's PSD allegations regarding past construction projects at Comanche Units 1 and 2 render the emission reductions at those units non-creditable for netting purposes. Again, we disagree. The Workshop Manual clarifies that "[a] source cannot receive emission reduction credit for reducing any portion of actual emissions which resulted because the source was operating out of compliance."[3] The NPS comments suggest that because EPA has identified potential violations of the NSR program at Comanche Units 1 and 2, that the current emissions at those units are presumptively in excess of compliance-level emissions, and cannot therefore form the basis of creditable emissions decreases.[4] The EPA's allegations of noncompliance are far from demonstrating noncompliance at Comanche Units 1 and 2. First and foremost, a mere allegation of noncompliance may not be treated as a final adjudication of the merits of the allegation. Second, PSCo wholly disagrees with the allegations made by the EPA with respect to compliance with NSR, and maintains that it has been and remains in compliance with all applicable requirements. And last, given the nationwide uncertainty with respect to EPA's novel NSR litigation theories, the emissions from Comanche Units 1 and 2 must be presumptively considered as compliant until otherwise finally established. With the presumption that emissions from Comanche Units 1 and 2 are lawful, and the highly uncertain prospects that the EPA will pursue—much less prevail on—its enforcement theories, we believe the NPS's comments on this point should not form the basis for a permitting decision by Colorado.

3. PSCo's Comanche Title V permit has no heat input limits relevant to the creditability of emission reductions

The NPS asserts that it has "discovered that the existing Comanche boilers typically exceed the heat input rates contained in their Title V operating permit," thereby possibly rendering a portion of the emission reductions at those units non-creditable for netting purposes. The fact is that Comanche's Title V permit contains

3 *See* Workshop Manual at A.41.

4 *See* NPS Comments at 3.

no enforceable limits on heat input rates.[5] And because Comanche has never violated its actual Title V NO_x or SO_2 emission limits for the Units 1 and 2 boilers PSCo is not relying on reductions of excess emissions to support its netting analysis. Moreover, heat input-related matters have no impact on PSCo's air quality modeling. Accordingly, the allegation that PSCo has relied on excess emissions to support its netting analysis is inaccurate, and we believe the NPS's comments on this point should not form the basis for a permitting decision by Colorado.

4. PSCo's permit application correctly identifies BACT or BACT-equivalent emission controls for new Comanche Unit 3

a. PSCo's BACT equivalency analysis—though not required under NSR—concludes that neither CFB nor IGCC are BACT for new Comanche Unit 3

The NPS comments suggest that inherently lower-polluting processes should be considered in the top-down BACT process. Specifically, NPS suggests that PSCo should explain why neither circulating fluidized bed ("CFB") nor integrated gasification combined cycle ("IGCC") technologies qualify as BACT for this project. Our response is three-fold.

First and primarily, EPA does not require a source to analyze different combustor or electric generating technology designs in a top-down BACT review. Historically the permit applicant defines the source, and PSCo defined the Comanche 3 source as a pulverized coal-fired (PC) steam electric generating unit, or PC boiler. Historically in Colorado, once the permit applicant defines the source, the state of Colorado applies the BACT process for PSD pollutants to identify the best available technologies to control emissions from that source, in this case BACT to control the PSD pollutants (PM10) from a PC boiler. This is a matter left up to the states, and the State of Colorado has never required a source to change or modify the source design during the BACT process. Accordingly, the NPS comment that the APCD should consider IGCC or CFB in the context of a BACT analysis for a PC boiler is clearly contrary to established APCD practice and should therefore be rejected. Secondly, PSCo's September 10, 2004, permit application concludes that

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[5] *Accord* Title V Permit No. 96OPPB133 issued by Colorado to Public Service Co.— Comanche Station (June 1, 2002, rev. November 19, 2002) at 4–7 (hereinafter "Title V Permit").

the construction of Comanche Unit 3 is not an NSR major modification for SO_2 and NO_x because of the plant-wide emissions limitations taken for those pollutants. As a result, no top-down BACT analysis for these pollutants is required: the only PSD pollutants at issue at Comanche 3 are PM10, CO, HF and VOCs. IGCC, though an unproven technology in pilot study only, is intended as a electricity generating process that will reduce SO2 and NOx, not PM10, CO, HF and VOCs. Outside the context of a required top-down BACT analysis for NOx and SO2, the suggestion by NPS that PSCo is required to evaluate IGCC in a top-down BACT evaluation is clearly misplaced.

Regarding the CFB combustion option, CFB designs are limited to approximately 300 MW in size. Using the CFB approach would require three CFB units for the Unit 3 project compared to one PC unit for a 750 MW plant. Since the CFB option is not available in the 750 MW size range it was rejected. Also, three CFB units would be more expensive to build than would one PC unit and would result in higher operating costs to staff and operate three CFB units.

Finally, the Settlement Agreement concludes that the use of low-NO_x burners and selective catalytic reduction to achieve a NO_x emissions level of 0.08 lbs/MMBtu on a 30-day rolling average is equivalent to BACT. Likewise, the use of low-sulfur coal and a lime spray drier absorber for the control of SO_2 to an emissions level of 0.10 lbs/MMBtu on a 30-day rolling average is equivalent to BACT. The Settlement Agreement does not mention IGCC or CFB, but obviously does include a requirement that PSCo install LNB and FGD on Units 1 and 2.

In conclusion, neither Colorado nor EPA requires PSCo to conduct a top-down BACT analysis for IGCC or CFB for a PC boiler design;, PSCo has netted out of PSD for SO2 and NOx by agreeing to install pollution control equipment on Units 1 and 2 to reduce overall plant-wide emissions; and PSCo has entered into a Settlement Agreement with all major citizen organizations to install LNB and FGC on Units 1 and 2. Therefore the NPS comment regarding IGCC are without merit.

b. PSCo's BACT analysis for CO and PM_{10} is correct

The Comanche 3 CO emission rate of 0.15 Lb/MMBtu is equivalent to many other recently issued PSD permits for PC boilers such as the 750 MW Council Bluffs

Energy Center Unit 4 burning PRB coal with a CO emission rate limit of 0.154 Lb/MMBtu. Thus the CO emission rate is BACT as demonstrated by other recent permits.

The Comanche 3 PM_{10} (filterable) emission rate of 0.0130 Lb/MMBtu is lower than most recently issued PSD permits for PC boilers. The total PM_{10} (filterable and condensable) emission rate of 0.020 Lb/MMBtu should be compared to other recent PSD permit limits for <u>total</u> PM_{10} such as the 750 MW Council Bluffs Energy Center Unit 4 burning PRB coal with a total PM_{10} emission rate limit of 0.025 Lb/MMBtu.

5. PSCo's modeling results show no adverse air quality impacts

a. Modeling technical corrections

For our 24-hour PM_{10} ISC NAAQS modeling, we used potential to emit rates for Units 1-2. For SO_2, the potential to emit emissions for Units 1-3 were used in the ISC NAAQS modeling.

b. PM_{10} modeling issues

The total PM_{10} emission rate listed in Table 3-2 of the application includes:

Filterable PM_{10}:	100 lb/hr
Condensable Sulfuric Acid Mist:	25 lb/hr
Condensable Fluoride:	3.6 lb/hr
Condensable HCL:	4.8 lb/hr
Condensable Ammonium Sulfate:	8.2 lb/hr
Total	142 lb/hr

For the Unit 3 Project, condensable sulfuric acid mist was "netted out", and was not included in the CALPUFF/VISCREEN modeling. Filterable PM_{10} was grouped with fluoride and HCl to arrive at a total PM_{10} emission rate of 108.5 lb/hr, and modeled total sulfate using the ammonium sulfate emission rate of 8.2 lb/hr.

c. Short term emission limits

NPS suggested in its comments, and Mr. Machovec requested in his December 13, 2004, email that PSCo propose short term emission limits for PM_{10}, NO_x, and SO_2 for Units 1, 2, and 3. The basis of these suggestions and recommendations appears to be that the short term emission included in PSCo's air quality modeling should be supported by enforceable short term permit limits. Our response is two-fold.

First and primarily, PSCo's September 10, 2004, permit application concludes that the construction of Comanche Unit 3 is not an NSR major modification for SO_2 and NO_x because of the plant-wide emissions limitations ensures that emission increases resulting from the construction of Comanche 3 will remain below significance levels. As a result, no PSD air quality impact modeling for these pollutants is required. Because no modeling is required, we believe that NPS's comments on the question of whether appropriate short term limits were used in the modeling cannot form the basis for a permitting decision by Colorado.

PSCo has elected to conduct a voluntary visibility modeling analysis to demonstrate the overall visibility improvements of the Comanche 3 project, and provide the results to the APCD. In the Settlement Agreement with local citizens and environmental groups, PSCo agreed to install an FGD system on Unit 1 to provide even greater SO_2 emission reductions from the project. CH2MHill is currently modeling the emissions from Comanche based on the Settlement Agreement terms and conditions, and the results of this visibility analysis will be included in the addendum to the permit application that will be filed with the APCD in mid January 2005. The air quality impact analyses concludes that for all pollutants—including SO_2 and NO_x—there is no violation of any National Ambient Air Quality Standard for any Class I or Class II area. The analysis also shows that there is no violation of a Class I or Class II PSD increment for any pollutant, including SO_2 and NO_x. Last, the voluntary, non-binding air quality analysis demonstrates that there is no adverse impact to air quality related values (including visibility) in any mandatory federal Class I area or Class II area from the construction and operation of the Comanche Unit 3 project. In fact, due to the emissions reductions from the addition of LNB and FGD to Units 1 and 2, the modeling conclusively demonstrates air quality improvement. But this voluntary modeling effort should not in any way be interpreted as requiring PSCo to propose or accept short term emission limits for Units 1, 2, or 3 other than those otherwise required by federal law (e.g., NSPS limits) or required by the specific terms of the

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Settlement Agreement. Colorado's guidance on the application of short term emission limits not otherwise required by federal regulations is clear: non-federally-required short term limits are clearly not required and should not be placed into permits.[6] Because the short-term limits used in the voluntary modeling effort are *not* federally required (and not required by the Settlement Agreement), it would violate Colorado's Short Term Emissions policy to require emission limits shorter than 30-day rolling average emission limits in the Comanche 3 project permit. Please see the attached White Paper on Short Term Emission Limits.

We are pleased to have been able to submit these responses to the comments of NPS. If you have any questions regarding our response, or need additional information from us in support of our permit application, please do not hesitate to contact me at 720 286 5056 or at the above mail address.

Sincerely,

Robert L. Pearson

Robert L. Pearson, Ph.D., PE
Vice President

Attachment

[6] *See* April 23, 1998, memorandum from Dave Ouimette to Stationary Sources Program and Local Agencies entitled, "PS-Memo 98-3 Short Term Limits Policy."

White Paper

Short Term Emission Limits

Comanche Unit 3 Project

The Terms of the Settlement Agreement and Colorado's Short-term Emission Limit Policy Prohibit Requiring Short-term Limits for NO_x and SO_2 in the Comanche Unit 3 Project's Air Permits

It has been the formal policy of the Air Pollution Control Division (APCD) since 1998 to limit the use of short-term emission limits (less than 30-day rolling average limits) to specific federal or state applicable requirements. Nonetheless, in preliminary comments dated November 24, 2004, related to the permitting of the Comanche Unit 3 project, the National Park Service ("NPS") suggested—without reference to Colorado's long-standing policy—that Public Service Company of Colorado's ("PSCo") Comanche Unit 3 project permit should include short-term emission limits not otherwise required by law.[1] Because the NPS suggestion is plainly contrary to APCD's policy; contrary to the specific terms and conditions of the Settlement Agreement; and will have the effect of dramatically increasing regulatory uncertainty in state permitting processes, we respectfully request that APCD clarify that the Comanche permit will not include short-term emission limits for SO_2 and NOx (and specifically include the SO_2 and NOx emission limits referenced in the Settlement Agreement).

DISCUSSION

UNIT 3 PROJECT NETTING APPLICATION: The Comanche Unit 3 project application requests short-term PSD limits for PM_{10} and short-term NSPS limits for SO_2 and NO_x. The application requires PSCO to install LNB and FGD to achieve significant reductions in NOx and SO2 in order to "net". Therefore, the construction of Comanche Unit 3 project is not a major modification for SO_2 and NO_x because of the meaningful plant-wide emission reductions. As a result, PSD is inapplicable for SO_2 and NO_x, and no short-term emission limits at Unit 3 for these pollutants are required under the PSD program. The application concludes that the construction of Unit 3 project is, however, a major modification for PM_{10}. As a result, short-term limits for PM_{10} at Unit 3 would be entirely appropriate under the April 1998 policy. And because Comanche Unit 3 is subject to an NSPS standard, it is entirely appropriate under the policy to include NSPS-based short-term emission limits in the Unit 3 permit. But no short-term PSD limits for SO_2 or NO_x may be included in the Unit 3 permit (other than the 30-day and annual limits agreed to in the Settlement Agreement), and no short-term limits may be included at all in the permit for Units 1 and 2 as a result of the netting involved in the Unit 3 project (other than the limits agreed to in the Settlement Agreement or in the existing Title V permit).

SETTLEMENT AGREEMENT: On December 3, 2004 PSCo entered into a voluntary Settlement Agreement with all of the major citizen organizations in and

[1] *See* "National Park Service—Air Resources Division Comments on PSCO Major Modification to the Comanche Power Plant," (November 24, 2004) at 8 [hereinafter "NPS Draft Comments"].

around Pueblo, Colorado to resolve all issues (including air quality) concerning the Comanche Unit 3 project. Most importantly to this discussion, PSCo will, under the Settlement Agreement, install expensive pollution controls at Units 1 and 2, creating meaningful air pollution reductions at the Station.[2] But equally important, the Settlement Agreement requires rolling monthly and annual emission limits, consistent with the APCD STEL policy.[3] The Settlement Agreement specifically does not require shorter term emission limits for SO2 and NOx.

CDPHE SHORT TERM EMISSION LIMIT GUIDANCE: In a guidance document published on April 23, 1998,[4] APCD articulated its general rule that major stationary source permits will include only those short-term emission limits required pursuant to federal or state law.[5] If no applicable federal or state law requires the use of a short-term limit, the permit will include only annual and monthly limits.[6] As the policy clarifies, the only federal and state programs that require short-term limits are PSD, non-attainment new source review, NSPS, MACT, NESHAP, case-by-case RACT, and state Regulation 1.[7] Accordingly, major stationary source permits may not include short-term emission limits not specifically required by a statutory program.

This general rule is subject to only two exceptions, neither of which is applicable at Comanche Unit 3 project. The first exception applies if air quality modeling indicates a potential exceedence of the National Ambient Air Quality Standards.[8] None of the voluntary modeling at Comanche Station indicates a potential exceedence of the NAAQS.[9] The second exception applies only where the

[2] *See* Settlement Agreement dated December 3, 2004.

[3] *See id.* ¶¶ 3(A) and 4(A).

[4] *See* Memorandum dated April 23, 1998, from Dave Ouimette to Stationary Sources Program and Local Agencies, entitled "PS-Memo 98-3 Short Term Limits Policy" [hereinafter "PS-Memo 98-3"].

[5] *Id.* at 1 ("Any existing state or federal short term limits contained in or required by existing regulations will be placed in permits.").

[6] *Id.* at 1–2 ("Permits issued to major sources will contain annual and monthly limits, or, as appropriate, a twelve month rolling total in lieu of the annual and monthly limits.").

[7] *Id.* at 3.

[8] *Id.* at 3 ("If, under the conditions the source chooses to operate (which may need to be a permit term) the NAAQS is not violated, a short term limit is not required. If a NAAQS is violated, a short term limit may be needed in the permit.").

[9] Because there is no "significant net emissions increase" in SO_2 and NO_x for Unit 3, PSD modeling is not required for these pollutants. *See* Colorado Modeling Guidelines for Air Quality Permits (January 1, 2002) § 2.3.1 ("[M]ajor modifications *subject to PSD attainment area rules* are required to submit various types of modeling and/or analysis along with their permit application."); *accord*. Machovec Letter at 1 ("[T]he major source PSD air quality analysis requirements, including the AQRV/visibility analysis, do not apply for a given pollutant if the net change in emissions is below the PSD significant emission rates."). Nonetheless, PSCo has performed voluntary modeling using emission rates below NSPS-levels for SO_2 and NO_x that demonstrates no adverse impact on NAAQS

community surrounding the stationary source must be protected from short-term (*i.e.*, acute) adverse impacts.[10] There is no evidence that emissions from Comanche Unit 3 project have any localized acute adverse impacts. As a result, neither of the two exceptions to the general rule is applicable. The Comanche permit should therefore not contain any short-term emission limits not specifically required by federal or state law.

In addition to the April 1998 guidance, APCD published permit procedure guidance in June 1998 that implements the April 1998 policy.[11] The June 1998 policy requires APCD permit engineers to actively remove short-term emission limits from draft permits unless the limit is required under the April 1998 policy.[12] Under this permit procedure, short-term limits not specifically required by federal or state law *must be removed* from major stationary source permits.

COMANCHE UNIT 3 PROJECT MODELING: The details of the Comanche Unit 3 project modeling are contained in the application for the Permit to Construct for Comanche Unit 3. This modeling shows compliance with Class I and Class II NAAQS, Class I and Class II PSD increments and Class I air quality related values. Accordingly, the overall emission reductions involved in the Unit 3 project ensure that all ambient air quality standards are fully protected. Since the Unit 3 project results in a net decrease in SO2 and NOx emissions, there is no regulatory requirement for SO2 and NOx modeling (even though we have voluntarily provide it to demonstrate the air quality improvements of the project). Consequently, there is no need, and specifically no regulatory requirement, for short term emission limits for SO2 and NOx less than the 30-day rolling average limits provided in the Settlement Agreement.

CONCLUSION

Both the Settlement Agreement and the policies expressed by APCD in 1998 will be dramatically undercut if APCD requires that the Comanche Unit 3 permit

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compliance as a result of the construction of Unit 3. As a result, construction of Unit 3 will not adversely impact NAAQS compliance, and no protective short-term limit is required.

[10] *Id.* at 2 ("Short term limits may be imposed where needed to address potential adverse impacts on public health, welfare, or the environment in the surrounding community.").

[11] *See* Memorandum dated June 10, 1998, from Dennis M. Myers to CP Engineers, entitled "PS Memo 98-004 Processing of final approved permits" [hereinafter "PS Memo 98-004"]. PS-Memo 98-3 promised the June 10, 1998, implementation memorandum. *See* PS-Memo 98-3 at 1 ("In that regard, the Division will develop a procedural document, using this policy as a guide, to provide staff with further information on how to draft permits."). As a result, PS-Memo 98-3 and PS Memo 98-004 should be read together.

[12] *See* PS Memo 98-004 at 1 ("Remove short term emission limits and short term production limits where possible. . . . If there is a regulatory basis for the limit, then it should remain in the permit with the appropriate averaging time, as stated in the standard."). *See also id.* at 3 ("Remove short term limits where appropriate. (No modeling issues and no regulatory basis for short term limit)").

contain short-term PSD-based emission limits for SO_2 and NO_x. The Settlement Agreement was carefully crafted compromise that elicited concessions by the company as well as the various citizen groups, and the emission limits and startup, shutdown provisions are key conditions to that agreement. The CDPHE STEL policy also was a carefully crafted guidance document that occurred over several years. If APCD requires 24 hour limits for SO2 and NOx, that action could reopen the terms and conditions in the Settlement Agreement. Likewise if APCD requires 24 hour limits for SOx and NOx in this netting permit, that action will reopen the uncertainty and controversy that led to the creation of the 1998 policies in the first place. Aside from this uncertainty, including short-term emission limits at Comanche Unit 3 will set the precedent for imposing short-term limits on any minor modification. Indeed, if PSCo correctly understands the NPS preliminary comment letter suggesting that short-term emission limits be imposed on Units 1, 2, *and* 3, then any minor modification to a stationary source could require the imposition of short-term limits on *all* emission units at the source. APCD should avoid this likely unintended consequence by adhering to its 1998 guidance documents, and not impose short-term SO2 and NOx emission limits in the Unit 3 project permit.

STATE OF COLORADO

Bill Owens, Governor
Douglas H. Benevento, Executive Director

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Colorado Department of Public Health and Environment

JAN 13 2005

January 12, 2005

Ms. Liana Reilly
National Park Service
Air Resources Division
12795 W. Alameda Parkway
Lakewood, CO 80228

REF: Public Service Company – Comanche Station, Unit 3, FID # 1010003

SUBJECT: Response to Comments During Federal Land Manager's Review Period

Dear Ms. Reilly:

The comments you provided on the Comanche Unit 3 PSD permit application submitted by Xcel Energy on August 6, 2004 and supplemented on September 10, 2004 were received via e-mail on November 24, 2004, with a hard copy received on December 6, 2004. The comments were received during the federal land managers' (FLMs') 30-day review period specified in Colorado Regulation No. 3, Part D, Section XIII.A. Your comments indicate that the National Park Service (NPS) is unable to adequately determine the impacts from the proposed project due to incomplete/incorrect modeling and an insufficient best available control technology (BACT) analysis. As indicated in our letter to you dated October 25, 2004, the Division was aware that a revised modeling analysis would need to be submitted; however, we wanted your comments on the modeling analysis, so that any revised analysis would incorporate both the Division's and the FLMs' concerns. Note that upon submittal of a revised modeling analysis, the Division will give the FLMs another opportunity to review the application for adverse impacts on visibility or air quality related values. With that said, the Division has addressed your comments as follows:

Netting Issues

Comment: *<u>Actual Emissions for Baseline SO_2 and NO_X Emissions for Units 1 and 2 (page 1, last paragraph):</u> The NPS has indicated that they agree with the use of 2002 and 2003 actual emission data to set the baseline for Units 1 and 2. However, the NPS indicates that according to the U. S. EPA's Clean Air Markets (CAM) web site, the average annual emissions for Units 1 and 2 are 8,961 tons/yr of NO_X rather than the 8,881 tons/yr of NO_X indicated in the application. The NPS considers that the CAM emission data should be used, unless use of other data is justified by the source.*

Response: The emissions used by Xcel in the Unit 3 application to establish the baseline for Units 1 and 2 are based on actual emissions reported on APENs to the Division. Therefore, we consider that the baseline emissions for Units 1 and 2 indicated in the Unit 3 application are appropriate. It is not clear why there is a difference in the NO_X emissions reported on the APENS compared to the NO_X emissions indicated on the CAM website; however, the lower baseline level indicated in the Unit 3 application is more conservative for use in the netting analysis.

Comment: *Reductions of SO_2 and NO_X Emissions for Units 1 and 2 are not Creditable (page 2, under header "BART Eligibility"): The NPS has indicated that they do not believe that the reductions of SO_2 and NO_X from Units 1 and 2 are creditable because Units 1 and 2 are subject to best available retrofit technology (BART) requirements, pending EPA enforcement actions and perceived violations of the Title V permit.*

Response: The Division does not agree with the NPS's position that the SO_2 and NO_X emission reductions from Units 1 and 2 are not creditable and therefore cannot be used to "net-out" of PSD review for NO_X and SO_2. The regulations specify that a decrease in emissions is creditable only to the extent that: 1) the Division has not relied on it in issuing any PSD permit or in demonstrating attainment or reasonable further progress, 2) that the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions, 3) that the decrease is federally enforceable at and after the time that construction on the particular change begins and 4) that it has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change (Colorado Regulation No. 3, Part D, Sections II.A.27.g(i) through (iv)). The Division has not relied on reductions from Units 1 and 2 in another PSD permit, nor have emission reductions from these units been used to demonstrate attainment or reasonable further progress. In addition, old actual emissions for Units 1 and 2 exceed the new actual levels (i.e. requested emissions), which will be made federally enforceable in permits to be issued for Units 1 and 2. Finally, the Division considers that the decrease in emissions from Units 1 and 2 are of approximately the same qualitative significance for public health and welfare as the increased emissions from the proposed new Unit 3. Therefore, the Division considers that the NO_X and SO_2 reductions from Units 1 and 2 to be creditable for use in "netting-out" of PSD review for Unit 3.

The NPS indicated several reasons for considering the reductions not creditable. The Division's position on those issues are as follows:

BART

Presumably, the NPS believes that the reductions from Units 1 and 2 are not creditable since these units are subject to BART and BART is more stringent than the proposed reductions (under item 2 above, the allowable emissions should represent BART and BART emissions are lower than the new level of actual emissions (i.e. the requested levels) for Units 1 and 2). The regional haze requirements, of which BART is a part of, are proposed standards at this time. The May 5, 2004 proposal indicates that a State's regional haze implementation plan must be submitted no later than January 31, 2008, which implies that implementation of a final rule (when promulgated), would be far in the future. In addition, the May 5, 2004 proposal is a re-proposal of a July 2001 proposal, which implies that it may be some time before these rules are finalized and the date for implementation could be set even later. In addition, while the Division agrees that Units 1 and 2 are BART-eligible, the second component for required BART is that the source must be "reasonably anticipated to cause or contribute to any impairment of visibility in any mandatory Class I federal area." It is not clear whether emissions from Units 1 and 2 would meet this second component and be subject to BART. While the Division does not believe that potential future BART requirements would prevent the SO_2 and NO_X emission reductions from Units 1 and 2 from being creditable, the Division considers that the SO_2 and NO_X reductions taken for Units 1 and 2 at this time do not preclude those units from BART-eligibility in the future and future required reductions due to BART, if applicable.

EPA Enforcement Action

The U. S. EPA did issue a notice of violation (NOV) to Xcel Energy for alleged violations of the PSD review requirements on June 26, 2002. The NOV is only an allegation of a violation. As of the date of this letter, EPA has taken no additional action on this NOV, nor are we aware that EPA is actively pursuing this matter. Therefore, the Division considers that EPA's NOV does not prevent the reductions from Units 1 and 2 from being creditable.

Perceived Violations of the Title V Permit

The NPS indicates that operation of the Units 1 and 2 boilers typically exceed the heat input rates contained in the Title V operating permit (3,190 mmBtu/hr for Unit 1 and 3,122 mmBtu/hr for Unit 2) and that if past actual emissions exceed allowable emissions, such emissions are not creditable (again, under item 2 above, for netting either actual or allowable, whichever is lower is used as the baseline). The boiler heat input rates were included in the Title V permit to describe the equipment; they are not enforceable limits. The heat input rates for each unit were provided by the source in the Title V permit application and apparently were not based on design rates but actual coal quality data. The source has requested that the design heat input rates be reflected in the Title V operating permit (minor modification request received on October 6, 2004) and has submitted design documents verifying that the design rate of Units 1 and 2 (3,531 mmBtu/hr for Unit 1 and 3,482 mmBtu/hr for Unit 2) are higher than indicated in the Title V operating permit. In addition, documents are available in the Division's files confirming the higher design rate of Unit 2. The modified Title V operating permit should be issued the first week in January 2005. Please be aware that as indicated in the technical review document for the original Title V operating permit, the design heat rates are, for all practical purposes, maximum values; however, the maximum can vary depending on the quality of the fuel. Therefore, since the heat input rates for Units 1 and 2 are not allowable limits, actual SO_2 and NO_X emissions from Units 1 and 2 are creditable. The Division is not aware of any physical changes to the boilers that would increase the design rate.

BACT Review

Comment: *Unit 3 BACT Analysis, Circulating Fluidized Bed (CFB) (page 5): The NPS indicated that further justification for exclusion of the CFB as BACT is necessary.*

Response: As you mentioned, the New Source Review Workshop Manual (NSRWM) indicates EPA has not considered the BACT requirement as a means to redefine the source when considering available control options, but that states have the discretion to engage in a broader analysis and may require the applicant to include inherently lower-polluting processes in their BACT analysis. Xcel did include information on CFB in their application that eliminated CFB from the BACT analysis. While their analysis was not extremely detailed we do not believe that further justification is necessary. In the future, as our analysis progresses, the Division may request additional information from Xcel.

Comment: *Unit 3 BACT Analysis, PM_{10} (page 6): The NPS indicated that lower PM_{10} emission rates are achievable.*

Response: The Division agrees with the NPS, that lower filterable PM_{10} emission rates appear to be achievable. The RBLC information included in the Unit 3 application indicates a lower PM_{10} emission rate of 0.011 lb/mmBtu (JEA Northside) and a lower PM emission rate of 0.012 lb/mmBtu (Wygen 2) but no information is provided in the application as to why such emission rates would not be achievable by the proposed Unit 3. In addition, EPA Region VIII has commented on other proposed draft PSD permits for coal-fired boilers that a filterable PM_{10} emission limit of 0.012 lb/mmmBtu is achievable. The Division received a response to your comments on January 7, 2005 (see attached) from CH_2Mhill, on behalf of Xcel. In their January 7, 2005 comments, CH_2Mhill indicates that they consider the proposed BACT limit for PM_{10} to be correct. The Division has not completed our BACT review for this particular project yet. We will include the appropriate BACT limit for PM_{10} in the draft permit.

Comment: *Unit 3 BACT Analysis, CO (page 6): The NPS indicated that lower CO emission rates are achievable.*

Response: The Division agrees with the NPS, that a lower CO emission rate appears to be achievable. The RBLC information included in the Unit 3 application shows several units with lower CO emissions (Thoroughbred, Crown/Vista, INDELK, Old Dominion, Chambers Cogeneration and Santee Cooper) but no information is provided in the application as to why such emission rates would not be achievable by the proposed Unit 3. The Division received a response to your comments on January 7, 2005 (see attached) from CH_2Mhill, on behalf of Xcel. In their January 7, 2005 comments, CH_2Mhill indicates that they consider the proposed BACT limit for CO to be correct. The Division has not completed our BACT review for this particular project yet. We will include the appropriate BACT limit for CO in the draft permit.

Comment: *Unit 3 BACT Analysis, SO_2 and NO_X (pages 6 and 7): The NPS has indicated the SO_2 and NO_X limits that they consider would be appropriate BACT limits for SO_2 and NO_X.*

Response: As indicated previously, the Division considers that the emission reductions of SO_2 and NO_X from Units 1 and 2 are creditable and that Xcel can "net-out" of PSD review for SO_2 and NO_X. Since PSD review does not apply to SO_2 and NO_X, a BACT analysis for these pollutants is not required.

Modeling Analysis

Comment: *<u>Units 1 and 2 Actual Emission Rates for Use in the "Before-and-After" Visibility Analysis (page 4, under header for "Comanche 1 and 2 Current Actual Emissions"):</u> The NPS indicated the emission rates for NO_X, SO_2 and PM that they believe are appropriate for use in the "before-and-after" visibility analysis.*

Response: The "before-and-after" visibility analysis conducted by Xcel for PM_{10}, SO_2 and NO_X was a voluntary submittal. Since the net emission increase in SO_2 and NO_X emissions, on an annual basis, are below the PSD significance levels, a visibility analysis is not required for SO_2 and NO_X. You have suggested specific data to be used in the analysis as actual emissions ("before") for Units 1 and 2. As indicated in Xcel's August 6, 2004 letter to the Division, they indicated that the use of average actual emissions was used for the "before" analysis, since actual emissions are far below allowable emissions. The Division is willing to accept the use of average actual emission data to represent emissions "before" the modification, since the use of such data would result in a conservative analysis. However, if Xcel were to conduct a less conservative analysis, the Division would also accept the maximum actual short-term emission rates for SO_2 and NO_X (based on CEMS data), or the allowable short-term emission rates for SO_2, NO_X and PM to represent emissions "before" the modification.

Comment: *<u>Short-Term Emission Rates and NAAQS Analysis (page 8, 2nd paragraph below "Modeling Analysis for Modified Plant" header:</u> The NPS expressed concern over the lack of short-term emission limits on Unit 3, in addition to Units 1 and 2 and the ability to assess compliance with the short-term NAAQS and increment.*

Response: A variety of issues were brought up regarding lack of short-term emission limits and evaluation of short-term impacts and the Division has addressed what we perceive as the various issues as follows:

<u>Lack of Short-Term Emission Limits for Unit 3</u>

You have indicated that PSCo has proposed no short-term emission limits for Unit 3 for SO_2, NO_X and H_2SO_4. It is not the Division's policy to require short-term emission limits for emission units, unless such a short-term emission limit is required by a specific regulation (i.e. NSPS, Reg 1, or Reg 7), because a case-by-case emission limit is required (i.e. BACT, RACT or LAER), or to assure compliance with the NAAQS. Since PSCo is netting out of PSD review for SO_2, NO_X and H_2SO_4, BACT is not required for those pollutants and PSCo is not required to propose a short-term emission limit for Unit 3 with respect to those pollutants. However, Units 3 is subject to a short-term emission limit for SO_2 of 0.4 lb/mmBtu (3-hr rolling average) as specified in Colorado Regulation No. 1. Note that Units 1 and 2 are also subject to a short-term SO_2 emission limits of 1.2

lb/mmBtu (3-hr rolling average), as specified in Colorado Regulation No. 1. Unit 2 is subject to a short-term emission limit for NO_X of 0.7 lb/mmBtu (3-hr rolling average), as specified in 40 CFR Part 60 Subpart D.

Required Modeling Analysis

Xcel conducted a Class I significant impact analysis for PM_{10}. In the event the analysis indicates there would be a significant impact, a cumulative impact analysis for the Class I PM_{10} increment would be required at each significantly impacted Class I area. According to the initial modeling, Class I PM_{10} impacts will be insignificant. A Class I and Class II visibility analysis was also conducted for PM_{10}. Regarding near-field impacts, Xcel conducted a Class II significant impact analysis for PM_{10}, CO, lead, mercury, beryllium, fluorides, vinyl chloride and hydrogen sulfide and the results of those analyses indicated that impacts for all pollutants except PM_{10} were below the modeling/monitoring significance levels. Therefore, a Class II full impact analysis was required and conducted. The Class II PM_{10} modeling analysis included both the short-term and long-term NAAQS, as well as the Class II increment. The Division has indicated to Xcel that some corrections to emission rates used in the analyses are necessary and we expect Xcel to submit a revised analysis at a later date. Since there will be no net increase in SO_2 and NO_X emissions on an annual basis, the Division considers that no modeling for the annual NAAQS is required for these pollutants. However, since there is an increase in the short-term (3-hr rolling average) emission rate for SO_2, the Division has told Xcel that they need to conduct an analysis for the short-term (3-hr and 24-hr) SO_2 NAAQS and that such an analysis must be conducted at the allowable short-term emission rate, which is the Reg 1 SO_2 limitation (3-hr rolling average), unless another short-term emission rate (i.e. 24-hr limit or more stringent 3-hr average) is requested by Xcel.

Voluntary "Before-and-After" Visibility Analysis

Since there was no increase in NO_X, SO_2 or H_2SO_4 emissions, on an annual basis, a modeling analysis was not triggered for these pollutants. At the request of the Division, Xcel conducted a "before-and-after" visibility analysis including all species that affect visibility, including SO_2, NO_X, and PM_{10}. This analysis was submitted on a voluntary basis. The Division previously indicated what emission rates we would accept to represent "before" emissions in this analysis. The Division's goal for the "before-and-after" visibility analysis is to show how the modification, as constrained by the emission limits allowed under the permit, would affect the magnitude, frequency, and duration of visibility episodes at Class I areas. We would expect the "after" emissions to be based on the maximum allowable short-term emission rates, which is the Reg 1 SO_2 limitations (3-hr rolling average) and the NSPS NO_X limit for Unit 2 (3-hr rolling average, unless another short-term emission rate (i.e. 24-hr limit or more stringent 3-hr limit) is requested by Xcel. Based on the information in the Xcel's August 6, 2004 letter, "future actual emissions" were used in the "before-and-after" analysis to represent emissions "after" the modification. While the use of annual "future actual emissions" is useful for showing the impact on days when the 24-hour average emission rates are similar to those modeled, the actual short-term emissions rates could be significantly higher than the modeled rates on some days during a typical year of operation.

Comment: *Particulate Matter Emission Rates Used in VISCREEN and CALPUFF (page 8, last paragraph): The NPS indicated that the particulate matter emission rates included in these analyses were incorrect.*

Response: Based on the information in Table 3-2 of the application and the calculation sheets in Appendix C, total PM_{10} emissions from Unit 3 are 142 lbs/hr (this does not include PM_{10} emissions from the Unit 3 ash silo loading emissions as discussed in Doris Jung's comments on the Class II modeling). The calculation sheets in Appendix C indicate that condensable PM_{10} consists of H_2SO_4 (25 lbs/hr) as well as other compounds (HF, HCl and $(NH_4)_2SO_4$). Therefore, based on the NPS comments it appears that the modeling was conducted at emission rates below the requested level. The Division agrees that the emission rates used in the VISCREEN and CALPUFF analyses for Unit 3 should be based on requested PM_{10} (total) emissions.

Comment: *Changes to CALPUFF and CALMET Input Files (page 9, 1st paragraph): The NPS identified several settings that should be re-adjusted in the CALPUFF and CALMET input files.*

Response: The Division included the NPS comments in with our comments to Xcel on the long range transport CALPUFF modeling (December 13, 2004 letter from Chuck Machovec to James Nall). We expect Xcel to address these issues in their revised modeling analysis.

We appreciate the time you took to review and comment the modeling analysis and application for the proposed Unit 3 at Comanche Station. Please feel free to call me at (303) 692-3267 if you have any further questions.

Sincerely,

Jacqueline Joyce

Jacqueline Joyce
Permit Engineer
Stationary Sources Program
Air Pollution Control Division

cc: Hans Buennning, U. S. EPA Region VIII
Coleen Campbell, APCD
Doris Jung, APCD
Gary Magno, Xcel Energy
Chuck Machovec, APCD

(b) (5) AWP ACC

[redacted]

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Littleton, CO 80125
303-932-7610
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FAX COVER SHEET

FAX NUMBER TRANSMITTED TO: 303-312-6953

To: Jim Eppers
Of: US EPA Region 8 ENF-LEP
From: Joseph M. Santarella Jr.
Client/Matter: RMELC/Xcel Comanche
Date: April 15, 2005

DOCUMENTS	NUMBER OF PAGES*
NPS Comments	25
CH2MHill Response	13
APCD Response	7

COMMENTS:

Dear Jim - Per our telecom, I am transmitting the correspondence between NPS, CH2MHill and APCD regarding the implications of the EPA NOV issued to Xcel Energy for NSR violations at Comanche Station. Specific discussion regarding the EPA NOV may be found in the NPS comments at 1-5 in the narrative attachment, the CH2MHill response at 3, and the APCD response at 3. Let me know if you have any questions or if I may be of assistance.

Kindest regards,

Joe Santarella

P.S. I am sending the documents in two separate transmissions due to size.

* NOT COUNTING COVER SHEET. IF YOU DO NOT RECEIVE ALL PAGES, PLEASE TELEPHONE US IMMEDIATELY AT 303-932-7610.

United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

IN REPLY REFER TO:

November 24, 2004

N3615 (2350)

Jackie Joyce
Colorado Department of Public Health and Environment
4300 Cherry Creek DR S
Denver, Colorado 80246-1530

Dear Ms. Joyce:

Thank you for providing a copy of the permit application by Xcel Energy for the major modification Xcel is planning for its Comanche Power Plant. Xcel Energy, through its subsidiary Public Service of Colorado (PSCO), proposes to add a third (Unit 3), 750 megawatt (MW) pulverized coal (PC) fired, boiler to the two existing PC boilers at its Comanche plant near Pueblo, Colorado. Xcel proposes to show that addition of the third boiler, coupled with emission reductions at the two existing boilers via improved emission controls, will result in insignificant increases in sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Thus, Xcel believes that Unit 3 is not subject to PSD review for SO_2 and NO_x. Annual emissions from Unit 3 are estimated to be 3,250 tons of SO_2, 3,250 tons of NO_x, 4,876 tons of CO, 670 tons of PM (total), 621 tons of PM_{10} (total), 119 tons of VOCs and 110 tons of H_2SO_4.

The National Park Service (NPS) is interested in this project because the Comanche Power Plant is located approximately 100 kilometers east of Great Sand Dunes National Park (NP) and about 250 kilometers south of Rocky Mountain NP. NPS is further concerned about this modification because Rocky Mountain NP is in nonattainment for ozone.

We believe that this source with its major modification could impact both Great Sand Dunes and Rocky Mountain NPs. However, we are unable to comment as to what these impacts could be due to incomplete/incorrect modeling and an insufficient BACT analysis. We would like to take this opportunity to provide our comments on this application. Enclosed you will find our comments regarding the Air Quality Modeling Analysis and the Best Available Control Technologies that Xcel has proposed. These comments provide the rationale behind why NPS can not explicitly say what the impacts on our Class I areas may be. NPS looks forward to reviewing any subsequent modeling and BACT analyses to determine the potential impacts this major modification may have on our parks.

We appreciate the opportunity to comment on the Xcel application. If you have any questions regarding our comments, please contact me at (303) 987-6895.

Sincerely,

Liana Reilly
Environmental Protection Specialist
Policy, Planning and Permit Review Branch

Enclosures

National Park Service-Air Resources Division
Comments on PSCO Major Modification to the Comanche Power Plant
November 2004

Prevention of Significant Deterioration (PSD) Applicability

The 325 MW tangentially-fired Comanche Unit 1 was placed into service in 1973, with the 335 MW wall-fired, dry-bottom Unit 2 coming on line in 1975. Since both units were permitted prior to January 6, 1975, and entered into a program of continuous construction, they had "commenced construction" before the Prevention of Significant Deterioration (PSD) regulations became applicable.

PSCO proposes to add Low-NO_x Burners (LNB) to units 1 and 2 to reduce NO_x emissions, as well as a Lime Spray Drier (LSD) to Unit 2 to reduce SO_2 emissions. PSCO contends that it will thus net out of PSD review for NO_x, SO_2, sulfuric acid mist (H_2SO_4), and Total Reduced Sulfur (TRS). A 36% reduction in NO_x from units 1 and 2, and a 20% reduction in SO_2 from 2002-03 levels could provide the offsets needed. Assuming no change in coal quality or operation from 2002-03, a 36% reduction of NO_x could be achieved by installation of LNB which would achieve emission rates of 0.20 lb/mmBtu on both units.[1] The SO_2 emission target of 0.4 lb/mmBtu would be met by installing a LSD with an annual efficiency of 50% on Unit 2; this is well below the expected 85% - 95% efficiency for a dry scrubber.[2]

BACT was examined for the following components of Unit 3. The unit will be equipped with LNB, overfire air (OFA), and Selective Catalytic Reduction (SCR) for 77% control of NO_x emissions, LSD for 84% SO_2 control,[3] and a pulse-jet fabric filter (baghouse) to control filterable Particulate Matter below 10 microns diameter (PM_{10}). PSCO proposes that plant-wide emission caps be established at current levels of SO_2 and NO_x emissions. Unit 3 is expected to have a Potential to Emit (PTE) of 3,250 tons per year (tpy) SO_2, 3,250 tpy NO_x, 621 tpy PM_{10} (total), and 110 tpy H_2SO_4. Net emission increases are projected at 621 tpy PM_{10} (total). (PSD will also apply due to significant increases of carbon monoxide (CO), volatile organic compounds (VOC), and hydrogen fluoride (HF).

PSCO has proposed to net out of PSD review for SO_2 and NO_x by creating creditable contemporaneous reductions in emissions of those pollutants. PSCO has proposed use of actual emissions data from the most recent two calendar years—this is the recommended approach—to establish a baseline from which to calculate emission changes. PSCO proposes that these baselines be set at 16,502 tpy SO_2 and 8,881 tpy NO_x, and that these values be written into appropriate permits as enforceable plantwide limits. According to the EPA Clean Air Markets (CAM) database, Comanche's emissions for this period were

[1] This is also the presumptive BART emission rate proposed by EPA in May 2004 for NO_x from utility boilers.
[2] WRAP assumed 85% SO_2 control as its default value for Western coal-fired boilers. EPA's May 2004 BART proposal suggested 98% control or 0.10 – 0.15 lb/mmBtu.
[3] As discussed later under BACT, these levels of control are well below current practice for new boilers.

16,502 tpy SO_2 and 8,961 tpy NO_x. We recommend that the CAM data be used unless the PSCO data are shown to be more accurate and reliable.

PSCO also proposes to net out of PSD review for H_2SO_4 and other sulfur compounds potentially subject to PSD review. PSCO correctly notes that, because these emissions are probably directly proportional to SO_2 emissions, any action that nets out for SO_2 will likewise net out for these related sulfur compounds.

PSCO will not attempt to net out of PSD review for PM_{10}, CO, HF, and VOC, and will undergo full PSD review for these pollutants.

BART Eligibility

As both units 1 and 2 began operation between August 7, 1962, and August 7, 1977, they are eligible for additional controls under the Best Available Retrofit Technology (BART) requirements of the Clean Air Act. Congress adopted the BART statutes as part of its program to meet the national visibility goal of no human-caused visibility impairment in mandatory Class I areas. The statues require the use of the best available retrofit technologies for sources that came into operation between the dates listed above.[4]

As with BACT (discussed later), BART is determined on a case-by-case basis. As proposed by EPA in May 2004, the BART analysis begins with the identification of BART-eligible sources based upon start-up and construction dates, and whether the source falls into one of 26 categories (listed by EPA). If a source meets those criteria, it is BART-eligible. If a large utility boiler, for example, is believed subject to BART because of its eligibility, emissions, and proximity to a Class I area, an analysis may be conducted to determine if it has a significant impact on visibility there and the degree of emission reduction that could be achieved by applying current control technology. This control technology analysis is to be conducted from the top down; that is, by beginning with the best available control technology and evaluating it on the basis of its technical and economic feasibility, as well as the benefit to visibility that would be derived from its application. It is important to note that the BART analysis differs from the BACT analysis in that it includes a test for environmental benefit of the candidate control strategy.

One overarching issue raised by this application regards the ability of a BART-eligible source, such as the existing Comanche facility, to claim credit for reducing emissions from units that could be required to reduce emissions anyway under the BART provisions of the national visibility protection program. According to EPA's New Source Review Workshop Manual (NSRWM):

> The process used to determine whether there will be a net emissions increase will result uses the following equation:

[4] In reality, that has not proven to be the case, as boilers that became operational in the 1940's are still in service today.

Net Emissions Change
EQUALS
Emissions <u>increases</u> associated with the proposed modification
MINUS
Source-wide creditable contemporaneous emissions <u>decreases</u>
PLUS
Source-wide creditable contemporaneous emissions <u>increases</u>

The key issue is whether the reductions proposed by PSCO are "creditable." Here is what the NSRWM has to say:

III.B.4. CREDITABLE AMOUNT

As mentioned above, only contemporaneous and creditable emissions changes are considered in determining the source-wide net emissions change. All contemporaneous and creditable emissions increases and decreases at the source must, however, be considered. The amount of each contemporaneous and creditable emissions increase or decrease involves determining old and new actual annual emissions levels for each affected emission unit.

The following basic criteria should be used when quantifying the increase or decrease:

➢ For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. This "old" emissions level equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the change which resulted in the emissions increase. These emissions are calculated using the <u>actual</u> hours of operation, capacity, fuel combusted and other parameters which affected the unit's emissions over the 2-year averaging period.

➢ A source cannot receive emission reduction credit for reducing any portion of actual emissions which resulted because the source was operating out of compliance.

The determination of whether or not Comanche units 1 and 2 are operating in compliance with the BART provision needs to be done by modeling Comanche 1 and 2 to determine if they are having a significant impact on visibility on any mandatory federal Class I area. (Please refer to the next section for suggestions on how to accomplish this.)

Several other issues arise with regards to Comanche's option for obtaining credit reductions. First, it has come to our attention that both of the existing boilers at the Comanche station are subject to enforcement action by EPA for violations of New Source Review regulations. Emissions that would be reduced due to an enforcement action would not be applicable toward netting out of PSD. Furthermore, we have discovered that the existing Comanche boilers typically exceed the heat input rates contained in their Title V operating permit. It is therefore possible that, if some of Comanche's past emissions are found to exceed allowable rates, credit for reduction of those emissions could be disallowed. If enough reduction credits are lost by Comanche, Unit 3 may become subject to PSD for additional pollutants.

Comanche 1 and 2 Current Actual Emissions

PSCO was directed by the Colorado Department of Public Health and Environment (CDPHE) to model the Comanche facility in "before-and-after" conditions to estimate impacts upon visibility, among other parameters. To appropriately represent actual emissions from the past two years of operation (2002-03), the EPA Acid Rain Database was used to generate the following tables of actual emissions:

Table 1. Comanche Actual Emissions

	Max SO2 (lb/hr)			
Unit	3-hr Max	3-hr 99th %	24-hr Max	24-hr 99th %
1	3798	2900	3141	2668
2	6139	2971	5032	2868
1+2	9524	5682	8173	5353

	Max NOx (lb/hr)		Max PM (lb/hr)	
Unit	24-hr Max	24-hr 99th %	24-hr Max	24-hr 99th %
1	2444	1892	455	
2	1553	1453	426	
1+2	3240	3098	835	818

These are the emissions that would be modeled to determine if Comanche is significantly impacting visibility at a Class I area. The individual values for units 1 and 2 follow EPA guidance by using the maximum emission rate of each pollutant over the past two years for each boiler and for each relevant averaging time. (99^{th} percentile values are provided for comparison, only.) The combined values use the same approach after first adding the hourly values for both units. The filterable PM emission rates are based upon heat inputs multiplied by the 0.1 lb/mmBtu limit[5] contained in Comanche's Title V permit. PM speciation is provided in the attached Table 2.

Best Available Retrofit Technology (BART)

As discussed above, units 1 and 2 are BART-eligible, and EPA has proposed presumptive BART limits for SO_2 and NO_x for coal-fired boilers. If units 1 and 2 were to meet those limits, SO_2 emissions would be reduced by 82% from current levels. This is 62% more than PSCO is currently proposing. PSCO's current proposal would reduce SO_2 by only 20% from these boilers. On the other hand, PSCO's proposed NO_x controls for units 1 and 2 appear equivalent to EPA's presumptive BART proposal for NO_x. If implemented the units, would meet the proposed BART requirements for NO_x.

[5] The Title V limit applies to filterable PM only. Total PM emissions are likely to be two times higher.

Best Available Control Technology (BACT) Analysis for Unit #3

BACT definition and process: BACT applies to any pollutant for which there would be a significant net increase in emissions. EPA defines BACT as an emissions limitation. It is important to note that, because BACT is an emission limit, that emission limit can be set by the permitting authority without actually specifying the design of the emission source that is to meet that limit. Thus, a permitting authority has the power to set an emission limit that it has judged to represent BACT for a broad source category, and then allow the applicant the freedom to determine how to meet that emission limit. According to the EPA New Source Review Workshop Manual (NSRWM):

> Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives...However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire...there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis...In such cases, the permit agency may require the applicant to include the inherently lower-polluting process in the list of BACT candidates.

So, a permitting authority does have "the discretion to engage in a broader analysis if they so desire." NPS suggests that PSCO consider this option.

Clean Coal Technologies: One of the fundamental principles of pollution control is to minimize the amount of pollution generated in the first place. According to the EPA NSRWM:

> The first step in a "top-down" analysis is to identify, for the emissions unit in question...all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

As part of its BACT analysis, PSCO included analyses of the technical and economic feasibility of applying Integrated Gasification Combined Cycle (IGCC) and Circulating Fluidized Bed (CFB) combustion technology to generate an equivalent amount of electricity. While we understand that IGCC has been successfully demonstrated at Tampa (FL) Electric's Polk Power Station, we shall focus our comments on CFB technology such as that contained in the NEVCO-Sevier permit recently issued by UT DAQ.

Circulating Fluidized Bed: PSCO has concluded that CFB would not be economically feasible for its Comanche expansion project. However, this conclusion is based on the assumptions that application of CFB combustion technology in conjunction with modern emissions control technology would result in higher annual costs and emissions that are not substantially lower than its proposal. We are submitting information from other CFB boilers around the nation. For example, here are permit limits from some other CFB facilities:

- The Northhampton Generating station in Pennsylvania has a limit of 0.0088 lb/mmBtu (on filterable and condensable PM_{10}) using a fabric filter, and recently was tested at 0.0041-0.0045 lb/mmBtu.
- The NEVCO-Sevier permit issued by UT DAQ contains a 0.022 lb SO_2/mmBtu 30-day rolling average limit.
- The Kentucky Mountain Power permit issued by KY DEP on 5/04/01 limits NO_x to 0.07 lb/mmBtu on a 30-day rolling average basis. Estill Country (KY) Power has made a similar proposal.

PSCO should re-evaluate the cost-effectiveness of CFB using emission estimates that reflect current control capabilities. Because the NEVCO-Sevier permit issued by Utah is for a CFB boiler burning low-sulfur western coal similar to that at Comanche, it was used for a direct comparison. The relevant emission limits and emissions are summarized in the table below.

Table 3. PC vs. CFB Emissions

	PM10 (lb/mmBtu)	PM10 (tpy)	CO (lb/mmBtu)	CO (tpy)	VOC (lb/mmBtu)	VOC (tpy)
PSCO proposed PC	0.0192	621	0.15	4876	0.0037	119
PSCO using Utah CFB	0.0154	501	0.115	3738	0.005	161

Because BACT is an emission limit, and because the Utah CFB permit clearly indicates that lower emission rates can be achieved burning low-sulfur western coal by using Clean Coal CFB technology instead of PC technology, PSCO must provide justification why the lower emission limits achievable by CFB should not be considered BACT for this application.

PM_{10}: If we look at both CFB and PC coal-fired boilers in the attached Table 4, we find that at least three other projects (Northhampton, Deseret, Longview) would have lower total PM_{10} emissions than proposed by PSCO, and that five (BHP, Deseret, JEA, Steag, WYGEN 2) would have lower filterable PM_{10} emissions. PSCO must provide justification why the lower emission limits achievable by these other coal-fired boilers should not be considered BACT for this application.

CO: If Comanche 3 were to meet the same emission limits as the Utah CFB permit, CO emissions would be reduced by 1,138 tpy. PSCO must provide justification why the lower CO emission limit achievable by that coal-fired project should not be considered BACT for this application.

SO_2: If all other conditions are held constant, SO_2 removal efficiency increases with the concentration of SO_2 in the stack gas. So, it is reasonable to conclude that Comanche #3 should be able to meet or exceed the SO_2 removal efficiency demonstrated by other PC boilers burning coal with equal or lower uncontrolled SO_2 emissions. As a corollary, it is also reasonable to conclude that Comanche #3 should be able to achieve a lower specific emission rate (lb/mmBtu) than similar PC boilers burning coal with higher uncontrolled SO_2 emissions. Finally, it is expected that newer emission sources should be capable of achieving more efficient levels of pollutant removal than existing and/or retrofitted units.

Based on data provided in Table 5.b. for 24-hour block rolling averages:

- The 0.210 lb/mmBtu 24-hour average proposed by PSCO is very high when compared with the actual performance of similar boilers burning coal with higher uncontrolled emissions, and 3.5 times the emission rate proposed by STEAG on coal with uncontrolled emissions 2.6 times greater than Comanche's. A review of Table 5.b. finds at least 12 operating boilers burning coal with higher uncontrolled SO_2 emission rates than the 0.613 lb/mmBtu estimated for Comanche's coal, but with lower actual 99th percentile controlled 24-hour average SO_2 emission rates than the 0.210 lb/mmBtu rate modeled by PSCO. (For example, Navajo #1 achieved a 99th percentile emission rate of 0.064 lb/mmBtu in 2000 burning coal with 50% higher uncontrolled emissions.) Nine proposed boilers in Table 5.b. are expected to meet a lower 24-hour average limit than Comanche #3, but while burning coal with higher uncontrolled emissions. Because Comanche's coal is inherently lower in potential SO_2 emissions, it should be able to achieve a lower 24-hour average emission rate. If Comanche #3 were to achieve the same 0.064 lb/mmBtu emissions rate as Navajo #1; its emissions would be reduced by 69%.
- If all other conditions are held constant, SO_2 removal efficiency increases with the concentration of SO_2 in the stack gas. The 99th percentile 24-hour average SO_2 removal efficiencies of the Rawhide boiler burning coal cleaner than proposed for Comanche #3 were 69.1% to 77.5%, compared to 65.7% for Comanche #3 burning coal with higher uncontrolled emissions. It is reasonable to expect that a new coal-fired boiler using current wet scrubber technology could achieve at least 77.5+% removal efficiency on the Comanche coal as demonstrated by Rawhide in 2001. If Comanche #3 were to achieve 77.5% control, its proposed 24-hour block average emission rate would be reduced to 0.138 lb/mmBtu or by 34%.

Based on data provided in Table 5.d. for annual averages, the 0.100 lb/mmBtu 24-hour average proposed by PSCO is very high when compared with the actual performance of similar boilers burning coal with higher uncontrolled emissions, and 1.8 times the emission rate proposed by STEAG on coal with uncontrolled emissions 2.6 times greater than Comanche's. A review of Table 5.d. finds at least 18 operating boilers burning coal with higher uncontrolled SO_2 emission rates than the 0.613 lb/mmBtu estimated for Comanche's coal, but with lower actual controlled annual average SO_2 emission rates than the 0.100 lb/mmBtu rate modeled by PSCO. (For example, Navajo #2 achieved an annual emission rate of 0.035 lb/mmBtu in 2001 burning coal with 50% higher uncontrolled emissions.) Five proposed boilers in Table 5.d. are expected to meet a lower 24-hour average limit than Comanche #3, but while burning coal with higher uncontrolled emissions. Because Comanche's coal is inherently lower in potential SO_2 emissions, it should be able to achieve a lower annual average emission rate. If Comanche #3 were to achieve the same 0.035 lb/mmBtu emissions rate as Navajo #2, its emissions would be reduced by 65%, or 2112 tpy.

Although PSCO contends that it is not subject to BACT for SO_2, it could reduce SO_2 emissions significantly by applying BACT.

NO_x: PSCO has modeled a 24-hour NO_x rate of 1200 lb/hr (equivalent to 0.162 lb/mmBtu) and an annual NO_x rate of 0.10 lb/mmBtu. If one compares these rates to those in Tables 6.a. and 6.c., it can be seen that there are several boilers with lower limits or emissions. Table 6.a. shows four boilers operating with lower 24-hour NO_x emissions, and eight with proposed or issued lower 24-hour permit limits. Table 6.c. shows three boilers operating with lower annual NO_x emissions, and 17 with proposed or issued lower 24-hour permit limits.

Although PSCO contends that it is not subject to BACT for NO_x, it could reduce NO_x emissions significantly by applying BACT.

Modeling Analysis for Modified Plant

The initial Class I modeling was based on a protocol that was developed during the first half of 2004 between CDPHE, PSCO and the Federal Land Managers. This modeling was submitted to the State and the NPS in July, 2004. In this analysis, only PM emissions from the proposed Unit #3 were modeled, as PSCO claims that Unit #3 nets out of PSD review for SO_2 and NO_x because PSCO will control NO_x on existing units #1 and #2 and control SO_2 on Unit #2.

Because PSCO has proposed no formal limits on short-term emissions of SO_2, H_2SO_4, and NO_x, for Unit #3, and because short-term emissions from units #1 and #2 are unlimited, it is impossible to make a definitive judgment of PSCO's modeling of short-term impacts. For example, PSCO predicted that Unit #3 would have a significant impact on PM_{10} concentrations in the vicinity of the plant, and conducted a cumulative analysis to determine compliance with the National Ambient Air Quality Standards (NAAQS). However, allowable emissions must be used in NAAQS analyses, and in the absence of short-term limits on units #1 and #2, no valid modeling analysis can be conducted. A similar problem exists due to the lack of short-term SO_2 limits on Unit #3; even though Unit #3 would be required to operate under an annual plantwide cap, there would be no limits to insure that periods of above-average emissions would not violate a short-term NAAQS or Increment.

In its VISCREEN and CALPUFF analyses, PSCO modeled 108.5 lb/hr total PM, while the emission rate given for total PM is 142 lb/hr.[6] PSCO also modeled 8.2 lb/hr Primary Sulfate versus the 25 lb/hr rate provided in Table 3-2 of the application. This rate is much lower than would be expected.[7] NPS recommends that the modeling be done with the correct emission rate. This rate can be compared to estimated allowable emissions. Despite the lack of definite short-term emission limits, we can estimate allowable emissions by assuming that units #1 and #2 operate at their most-recent-two-year maximum heat inputs and at their Title V limits; those emission estimates are contained in the following table and attached Table 8.

[6] Application Table 3-2, p3-2.

[7] Use of AP-42 emission factors yields an estimate of 346 lb SO_4 /hr if filterable PM_{10} emissions are 100 lb/hr.

Table 7. Comanche Future Potential Emissions

	Max SO2 (lb/hr)		Max NOx (lb/hr)	Max HI (mmBtu/hr)	Filterable PM (lb/hr)
Unit	3-hr Max	24-hr Max	24-hr Max	24-hr Max	24-hr Max
1	6005	6005	3503	5004	500
2	5247	5247	3061	4373	437
3	?	1557	1200	7421	100

On October 27, 2004, both PSCO and NPS received an e-mail from CDPHE regarding their recommendations of changes to the initial CALMET and CALPUFF input files. The NPS agrees with some of CDPHE recommendations. Below are additional recommendations and concurrence with CDPHE recommendations regarding the modeling analysis.

The most compelling reason for PSCO to re-do their air quality analysis is that the CALMET computer code that was used in the initial analysis contained errors. During the initial negotiations on the Class I modeling protocol, PSCO stated that they wanted to use the latest version of the CALPUFF/CALMET modeling system available from the EPA's CALPUFF contractor, Earth Teck. Both the NPS and CDPHE agreed with this request. The modeling that PSCO submitted in July 2004 used a version of CALMET computer code that was compiled on January 20, 2004. Unfortunately, through no fault of PSCO's, there was an error discovered in the CALMET code that PSCO used to compile its January 2004 version of CALMET. This error in the CALMET code was corrected, and the corrected version was posted on the Earth Teck web site on July 16, 2004. Therefore, PSCO should submit the revised modeling using the latest corrected version of the CALPUFF/CALMET modeling system posted on the Earth Teck web site.

Based on information that CDPHE has recently supplied, the NPS concurs that the variable for the maximum mixing height overland (ZIMAX) needs to be changed from the initial input. Based on soundings taken along the Colorado Front range CDPHE believes that the summer daytime mixing heights range between 2000 meters to 4500 meters above ground level (AGL). We concur with CDPHE's recommendation to set ZIMAX to 4500 meters. The variables (NZ=11) the number of vertical layers, and ZFACE which sets the cell face heights can remain as in the initial analysis.

The NPS disagrees with both CDPHE's and PSCO's proposed settings for the variable (BIAS). These settings for each vertical cell indicate the interpolated weighting of surface meteorological and upper air data. Both CDPHE and PSCO want to reduce the influence of the upper air data in the lowest two layers beyond the recommended default values. The NPS recommends that the default values of 0.0 be used for the 11 vertical layers in the analysis which lets the normal interpolation scheme in CALMET be used.

In the initial analysis, RMIN2 is set at (-1), its default is a value of (4), and the re-analysis should set the value to (4). Because PSCO correctly set the variable IXTERP to (-4), CALMET internally reset RMIN2 to (4). NPS believes that the value for RMIN2 should be set to (4).

NPS believes that the surface stations will have influence farther than 10km. NPS thus suggests that the variable RMAX1 be increased to 30 km from the initial 10 km setting. Also, the variable R1 should be increased from 4 km to 30 km so that the surface observations are not overwhelmed by the first guess field. The variable R2 was set to 40 km in the initial analysis; it should be increased to 50 km to better weigh the observed upper air observations.

Finally, the CALPUFF input file needs to include speciated PM emissions as described in the BACT comments. That is, the emissions need to include the filterable PM emissions of coarse and fine primary emissions and elemental carbon (EC). The condensable PM emissions should include sulfate emissions and organic carbon (SOA). These PM emissions should also be included in the wet and dry deposition output files. Also, should netting of SO_2 and NO_x emissions not be allowed, they too need to be modeled.

Conclusions & Recommendations

Comanche 1 and 2 are BART-eligible and may be subject to BART if they are shown to have a significant impact upon visibility in a Class I area. While the NO_x controls proposed for Comanche 1 and 2 may be equivalent to the presumptive BART levels proposed by EPA, the SO_2 controls fall far short of EPA's presumptive BART levels. NPS should evaluate these units to determine if they significantly impact a Class I area and if BART should apply.

The emission rates proposed by PSCO to represent past actual emissions appear reasonable. However, if these emissions exceed allowable emission rates (due to BART or NSR non-compliance issues), then reductions from those rates may not be entirely creditable. If that is the case, then Comanche may not avoid PSD review for SO_2 and NO_x. If PSD applies to Comanche unit 3 for SO_2 and NO_x, the emission rates to be achieved do not represent BACT. Furthermore, if PSD applies to additional units and/or additional pollutants, then additional BACT analyses are required.

Because BACT is an emission limit, and because CFB technology can achieve lower emission limits for combustion of the type of coal burned at Comanche, PSCO must conduct a more rigorous evaluation of the option to use CFB Clean Coal Technology at Comanche.

The PM_{10} emission rates proposed by PSCO are higher than several recent permit applications. PSCO must justify why it cannot meet similar limits.

The lack of short-term limits on emissions from Comanche 1 and 2 make it difficult to determine if NAAQS and Increments are being protected around the plant. If Comanche unit 3 has no short-term limits on SO_2 and NO_x, it will also be impossible to determine its impacts upon visibility. Furthermore, the PM_{10} and SO_4 emission rates PSCO modeled are less than the rates presented in the application. PSCO should propose short-tem emission limits for all boilers at Comanche and model those rates to demonstrate that all NAAQS, Increments, and Air Quality Related Values (e.g., visibility) are protected.

PSCO should re-do all of its modeling to use the correct CALMET computer code and appropriate settings identified above.

Table 2.a.
Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only Fabric Filter for Emissions control

based on Comancho Unit #1 Max 2002-2003 24-hr Heat Input
assumes heating value of 9929 Btu/lb and a sulfur content of 0.40 % and an ash content of 4.60 %

	Controlled PM10 Emissions (Bold values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0146	0.0046	0.0023	0.6	0.0023	0.0022	1	0.00009	10	0.010	0.008	SO4	3*f(RH)	0.002	SOA	4

	Controlled PM10 Emissions (Bold Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.291	0.092	0.046	0.6	0.046	0.044	1	0.0017	10	0.199	0.159	SO4	3*f(RH)	0.040	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	32%	15.8%	0.6	15.8%	15.2%	1	0.6%	10	68%	54.7%	SO4	3*f(RH)	13.7%	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	1	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	1437	455	227	0.6	227	219	1	8	10	982	785	SO4	3*f(RH)	196	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Filterable)	Coef.	(% of Filterable)	(% of Filterable)	1	(% of Filterable)	Coef.	(% of Total)	(% of Condensible)	Type	Ext.Coef.	(% of Condensible)	Type	Ext.Coef.
PC-DB	100%	32%	50%	0.6	50.0%	48.2%	1	1.8%	10	68%	80%	SO4	3*f(RH)	20%	SOA	4
						(% of Fine)	Coef.	(% of Fine)	Coef.							
						98.3%	1	3.7%	10							

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	[illegible]	[illegible]	Fine	[illegible]	[illegible]	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	[illegible]	[illegible]	(lb/hr)	[illegible]	[illegible]	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	1437	455	[illegible]	[illegible]	227	[illegible]	[illegible]	[illegible]	[illegible]	982	785	SO4	3*f(RH)	196	SOA	4

Table 2.b.
Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only Fabric Filter for Emissions control

based on Comanche Unit #2 Max 2002-2003 24-hr Heat Input
assumes heating value of 9929 Btu/lb and a sulfur content of 0.40 % and an ash content of 4.60 %

Controlled PM10 Emissions (Bold values from Table 1.1-5.)

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0146	0.0046	0.0023	0.6	0.0023	0.0022	1	0.00009	10	0.010	0.008	SO4	3*f(RH)	0.002	SOA	4

Controlled PM10 Emissions (Bold Values from Table 1.1-6.)

Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.291	0.092	0.046	0.6	0.046	0.044	1	0.0017	10	0.199	0.159	SO4	3*f(RH)	0.040	SOA	4

Controlled PM10 Emissions

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	32%	15.8%	0.6	15.8%	15.2%	1	0.6%	10	68%	54.7%	SO4	3*f(RH)	13.7%	SOA	4

Controlled PM10 Emissions

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	1346	426	213	0.6	213	205	1	8	10	920	736	SO4	3*f(RH)	184	SOA	4

Controlled PM10 Emissions

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Filterable)	Ext. Coef.	Fine (% of Filterable)	Fine Soil (% of Filterable)	Ext. 1	Fine EC (% of Filterable)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Condensible)	Particle Type	Particle Ext.Coef.	CPM OR (% of Condensible)	Particle Type	Particle Ext.Coef.
PC-DB	100%	32%	50%	0.6	50.0%	48.2%	1	1.9%	10	68%	80%	SO4	3*f(RH)	20%	SOA	4
						(% of Fine)	Coef.	(% of Fine)	Coef.							
						96.3%	1	3.7%	10							

Controlled PM10 Emissions

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	[illegible]	[illegible]	Fine (lb/hr)	[illegible]	[illegible]	Fine EC [illegible]	Ext. [illegible]	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	1346	426	[illegible]	[illegible]	213	[illegible]	[illegible]	[illegible]	10	920	736	SO4	3*f(RH)	184	SOA	4

Table 4. PM10 Rankings

									Emission Limits					Emission Limits	
				Issue	Boiler	Capacity			Filterable PM10		Period	Control		Total PM10	
Facility Name/Location	Unit	Status	Permit #	Date	Type	MW	Total	(mmBtu/hr)	(lb/mmBtu)	(lb/hr)	(hr)	Type	(%)	(lb/mmBtu)	(lb/hr)
Northhampton Gen. Co.		operating	PA-0134	04/14/95	FB			1146			3	FF		0.0088	
Deseret	2	pending	UT		CFB	110	110	1478	0.012	17.7	3	FF		0.017	25.1
Longview Power		issued	WV	03/01/04	PC	600	600	6114			3	FF		0.018	110
Comanche	**3**	**application**	**CO**		**PC**	**750**	**1950**	**7421**	**0.0135**	**100.2**	**3**	**FF**		**0.019**	**141.9**
STEAG-Desert Rock		application	NEPA		PC	750	1500	13620	0.010	136	3	FF		0.020	272.4
JEA Repower		issued	FL-0178		CFB	2x298	598	5528	0.011		3	FF/ESP			
BHP		on hold	NEPA		PC	560	550	5111	0.012		3	FF			
Black Hills Pwr-Wygen2	2	issued	WY	09/25/02	PC	500	500	5148	0.012	61.7		FF	99.9%		

Table 5.a. SO2 Rankings (1- & 3-hr averaging periods)

SO2				Issue/Op	Boiler	Coal Quality					Capacity			Emissions or Limits*		Period	Control	
Facility Name	Unit	Status	Permit #	Date	Type	Year	%S	(Btu/lb)	(lb/mmBtu)	Year	MW	Total	(mmBtu/hr)	(lb/mmBtu)	(lb/hr)	(hr)	Type	(%)
Rawhide	101	operating	CO		PC	2000	0.20	8821	0.397	2000	285	285	3433	0.108	448	3	LSD	72.8%
Rawhide	101	operating	CO		PC	2001	0.23	8832	0.456	2001	285	285	3348	0.111	545	3	LSD	75.6%
Comancho	3	application	CO		PC		0.29	8200	0.613		750	1950				3	LSD	
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	9762	0.123	1323	3	WLS	84.1%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	10341	0.092	1080	3	WLS	88.1%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2001	820	820	9523	0.110	1105	3	WLS	86.6%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2001	820	820	10105	0.109	1149	3	WLS	86.7%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2002	820	820	8573	0.099	1316	3	WLS	87.9%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.61	11818	0.820	2002	820	820	1033	0.097	1319	3	WLS	88.2%
Navajo	1	operating	AZ		PC	2000	0.63	10919	0.922	2000	803	803	9100	0.084	13157	3	WLS	93.1%
Navajo	2	operating	AZ		PC	2001	0.53	10909	0.923	2001	803	803	8814	0.050	3195	3	WLS	94.6%
Navajo	3	operating	AZ		PC	2001	0.63	10909	0.923	2001	803	803	9218	0.094	1812	3	WLS	89.8%
Navajo	3	operating	AZ		PC	2001	0.63	10909	0.923	2002	803	803	9247	0.155	3889	3	WLS	83.2%
STEAG-Desert Rock		application	NEPA		PC		0.82	8910	1.611		750	1500	13620	0.090	1226	3	WLS	84.4%
Red Trail Energy		pending	ND		CFB		1.20	6900	3.043				250	0.090	23	1	LSD	97.0%

* Actual emissions from existing sources or proposed or permited limits for new sources

Table 5.b. SO2 Rankings (24-hr averaging period)

SO2				Issue	Boiler	Coal Quality					Capacity			Emissions or Limits*		Period	Control	
Facility Name	Unit	Status	Permit #	Date	Type	Year	%S	(Btu/lb)	(lb/mmBtu)	Year	MW	Total	(mmBtu/hr)	(lb/mmBtu)	(lb/hr)	(hr)	Type	(%)
Rawhide	101	operating	CO		PC	2000	0.20	8821	0.397	2000	285	285	3340	0.123	324	24	LSD	69.1%
Rawhide	101	operating	CO		PC	2001	0.23	8632	0.456	2001	285	285	3305	0.103	318	24	LSD	77.5%
Comanche	3	application	CO		PC		0.28	8200	0.813		750	1950	7421	0.210	1557	24	LSD	65.7%
NEVCO-Sevier		pending	UT		CFB		0.90	10200	1.544		270	270	2532	0.050	127	24	CFB/CDS	96.8%
STEAG-Desert Rock		application	NEPA		PC		0.82	6910	1.611		750	1500	13620	0.060	817	24	WLS	96.3%
Navajo	1	operating	AZ		PC	2000	0.63	10919	0.922	2000	803	803	8752	0.064	5639	24	WLS	93.1%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	9647	0.092	884	24	WLS	88.3%
Navajo	2	operating	AZ		PC	2001	0.63	10909	0.923	2001	803	803	9072	0.086	724	24	WLS	90.7%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.61	11819	0.820	2002	820	820	9480	0.087	888	24	WLS	89.4%
Coronado	2	operating	AZ		DB-Turbo		0.45	9739		2002			4477	0.089	398	24		87.8%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2002	820	820	9747	0.080	835	24	WLS	89.0%
Red Trail Energy		pending	ND		CFB		1.20	6900	3.043				260	0.090	23	24	LSD	97.0%
Conemaugh	1	operating	PA		PC	1997	2.22	12532	3.366	2002	936	936	7976	0.094	753	24	WLS	87.0%
Bonanza	1	operating	UT	2/04/81	PC	2001	0.40	9929	0.705	2001	400	400	5727	0.085	485	24	WLS	86.6%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2001	820	820	9881	0.099	978	24	WLS	87.9%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2001	820	820	9180	0.100	957	24	WLS	87.8%
Navajo	3	operating	AZ		PC	2001	0.53	10908	0.923	2001	803	803	9132	0.101	959	24	WLS	93.1%
Colstrip	3	operating	MT	8/11/1979	PC	2000	0.75	8487	1.546	2002	778	778	8777	0.104	1149	24	WLS	93.5%
Colstrip	4	operating	MT	8/11/1979	PC	2000	0.75	8487	1.546	2000	778	778	9388	0.110	895	24	WLS	92.9%
Colstrip	3	operating	MT	8/11/1979	PC	2000	0.75	8487	1.546	2001	778	778	8767	0.118	994	24	WLS	92.3%
Intermountain Pwr Project	3	issued	UT	10/15/04	W-DB-PC		0.75	11193	1.273		950		9050	0.120	1088	24	WLS	90.6%
Bull Mountain-Roundup		issued	MT	01/31/03	PC		0.84	9921	1.695	2000	2x390	780	8028	0.120	963	24	LSD	93.7%
Longview Power		issued	WV	03/01/04	PC		2.6	11750	4.043		600	600	6114	0.120	734	24	WLS	97.0%
Colstrip	3	operating	MT	8/11/1979	PC	2000	0.75	8487	1.546	2000	778	778	8859	0.121	921	24	WLS	92.2%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	9848	0.122	1182	24	WLS	84.3%
Colstrip	4	operating	MT	8/11/1979	PC	2000	0.75	8487	1.546	2001	778	778	9462	0.125	1184	24	WLS	91.9%
Conemaugh	1	operating	PA							2001			8527	0.137	1172	24		92.1%
Navajo	3	operating	AZ		PC	2001	0.63	10909	0.923	2002	803	803	9157	0.138	1124	24	WLS	85.0%
Conemaugh	2	operating	PA							2001			8313	0.142	1181	24		91.9%
Bonanza	1	operating	UT	2/04/81	PC	2001	0.40	9929	0.705	2002	400	400	5857	0.143	841	24	WLS	79.8%
Conemaugh	2	operating	PA		PC	1997	2.22	12532	3.366	2002	936	936	8111	0.144	1160	24	WLS	80.1%
Colstrip	4	operating	MT	8/11/1979	PC	2000	0.75	8487	1.546	2002	778	778	8894	0.146	881	24	WLS	80.9%
Black Hills Pwr-Wygen2		appealed	WY	09/25/02	PC		1.20	7950	2.642		500	500	5146	0.150	772	24	LSD	94.3%
Craig	3	operating	CO	?	DB-PC	2001	0.38	10181	0.653	2001	446	446	4545	0.156	710	24	DL	78.9%
Navajo	1	operating	AZ		PC	2001	0.53	10909	0.923	2001	803	803	8218	0.179	2348	24	WLS	80.6%
N. Amer. Pwr-Mid PRB		dead	WY		PC		0.40	8530	0.821		500	500	4664	0.180	840	24	LSD	78.1%
Two Elk #2		dead	WY		PC		0.40	8530	0.821		500	500	4664	0.180	840	24	LSD	78.1%
Bonanza	1	operating	UT	2/04/81	PC	2000	0.40	10008	0.688	2000	400	400	6466	0.185	848	24	WLS	72.1%
Navajo	1	operating	AZ		PC	2001	0.53	10909	0.923	2002	803	803	8690	0.202	542	24	WLS	78.1%

* Actual emissions from existing sources or proposed or permitted limits for new sources

Table 5.c. SO2 Rankings (30-day averaging period)

SO2				Issue	Boiler	Coal Quality					Capacity			Emissions or Limits*		Period	Control	
Facility Name	Unit	Status	Permit #	Date	Type	Year	%S	(Btu/lb)	(lb/mmBtu)	Year	MW	Total	(mmBtu/hr)	(lb/mmBtu)	(lb/hr)	(hr)	Type	(%)
Rawhide	101	operating	CO		PC	2000	0.20	8621	0.397	2000	285	285	3271	0.081	252	720	LSD	79.5%
Rawhide	101	operating	CO		PC	2001	0.23	8832	0.456	2001	286	286	3242	0.092	273	720	LSD	79.9%
Comanche	3	application	CO		PC		0.28	8200	0.613		750	1950						
Craig	3	operating	CO	?	W-DB-PC	2001	0.38	10181	0.653	2002	446	446	3972	0.118	432	720	DL	82.2%
Bonanza	1	operating	UT	2/04/81	PC	2000	0.40	10008	0.609	2000	400	400	5114	0.091	330	720	WLS	87.0%
Bonanza	1	operating	UT	2/04/81	PC	2001	0.40	9929	0.705	2001	400	400	5289	0.068	328	720	WLS	90.4%
Bonanza	1	operating	UT	2/04/81	PC	2001	0.40	9929	0.705	2002	400	400	5760	0.071	227	720	WLS	89.9%
Hunter (Emery)	3	operating	UT	1983	W-DB-PC	2000	0.45	11784	0.728	2000	495	496	4273	0.087	341	720	WLS	88.5%
Hunter (Emery)	3	operating	UT	1983	W-DB-PC	2000	0.45	11784	0.728	2002	495	496	4249	0.109	465	720	WLS	85.7%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	9487	0.082	754	720	WLS	89.4%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	9498	0.059	566	720	WLS	92.3%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2001	820	820	8748	0.070	607	720	WLS	91.6%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2001	820	820	9626	0.073	651	720	WLS	91.2%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2002	820	820	9008	0.064	558	720	WLS	92.2%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2002	820	820	9220	0.083	566	720	WLS	92.4%
Navajo	1	operating	AZ		PC	2000	0.53	10919	0.922	2000	803	803	8030	0.109	553	720	WLS	88.1%
Navajo	2	operating	AZ		PC	2000	0.53	10919	0.922	2000	803	803	8206	0.293	2469	720	WLS	68.3%
Navajo	3	operating	AZ		PC	2000	0.53	10919	0.922	2000	803	803	6679	0.097	778	720	WLS	89.4%
Navajo	1	operating	AZ		PC	2001	0.53	10909	0.923	2001	803	803	7875	0.091	435	720	WLS	90.1%
Navajo	2	operating	AZ		PC	2001	0.53	10909	0.923	2001	803	803	8563	0.044	323	720	WLS	95.2%
Navajo	3	operating	AZ		PC	2001	0.53	10909	0.923	2001	803	803	8949	0.064	396	720	WLS	93.1%
Navajo	1	operating	AZ		PC	2001	0.53	10909	0.923	2002	803	803	8184	0.053	401	720	WLS	94.3%
Navajo	2	operating	AZ		PC	2001	0.53	10909	0.923	2002	803	803	8973	0.066	336	720	WLS	92.9%
Navajo	3	operating	AZ		PC	2001	0.53	10909	0.923	2002	803	803	9066	0.071	472	720	WLS	92.3%
Intermountain Pwr Project	3	issued	UT	10/15/04	W-DB-PC	[redacted]	0.75	11193	1.273	[redacted]	950		9050	0.100	905	720	WLS	92.1%
Colstrip	3	operating	MT	9/11/1979	PC	2000	0.75	8487	1.546	2000	778	778	7790	0.114	858	720	WLS	93.4%
Colstrip	4	operating	MT	9/11/1979	PC	2000	0.75	8487	1.546	2000	778	778	8747	0.091	761	720	WLS	94.5%
Colstrip	3	operating	MT	9/11/1979	PC	2000	0.75	8487	1.546	2001	778	778	8624	0.115	860	720	WLS	92.7%
Colstrip	4	operating	MT	9/11/1979	PC	2000	0.75	8487	1.546	2001	778	778	8816	0.093	807	720	WLS	94.4%
Colstrip	3	operating	MT	9/11/1979	PC	#REF!	0.75	8487	1.546	2002	778	778	8564	0.061	523	720	WLS	91.8%
Colstrip	4	operating	MT	9/11/1979	PC	2000	0.75	8487	1.546	2002	778	778	8534	0.062	525	720	WLS	91.0%
STEAG-Desert Rock		application	NEPA		PC		0.82	8910	1.611		760	1500	13620	0.060	817	720	WLS	0.0%
Bull Mountain-Roundup		issued	MT	01/31/03	PC		0.94	9921	1.895		2x390	780	8026	0.120	963	720	LSD	93.7%
Black Hills Pwr-Wygen2		appealed	WY	09/25/02	PC		1.20	7950	2.642		500	500	5140	0.100	515	720	LSD	98.2%
Red Trail Energy		pending	ND		CFB		1.20	6900	3.043				250	0.090	23	720	LSD	95.6%
Mustang		pending	NM		PC		1.66	8647	3.157		300	300	3192	0.108	345	720	CDS	96.6%
Gascoyne		issued	ND		CFB		1.07	5660	3.287		175	175	2112	0.038	80	720		98.8%
Conemaugh	1-PN	operating	PA		PC	1997	2.22	12532	3.366	2002	936	936	7731.74	0.061	473	720	WLS	91.8%
Conemaugh	2-PN	operating	PA		PC	1997	2.22	12532	3.366	2002	936	936	7773.12	0.070	543	720	WLS	90.8%
Longview Power		issued	WV	03/01/04	PC		2.6	11750	4.043		600	600	6114	0.120	734	720	WLS	97.0%
Deseret	2	pending	UT		CFB		1.00	4000	4.376		110	110	1478	0.100	148	720	LSD	97.7%
NEVCO-Sevier		pending	UT		CFB		#REF!	#REF!	#REF!		270	270	2532	#REF!	#REF!	720	CFB/CDS	#REF!

* Actual emissions from existing sources or proposed or permitted limits for new sources

Table 5.d. SO2 Rankings (Annual averaging period)

SO2				Issue	Boiler	Coal Quality					Capacity			Emissions or Limits*		Period	Control	
Facility Name	Unit	Status	Permit #	Date	Type	Year	%S	(Btu/lb)	(lb/mmBtu)	Year	MW	Total	(mmBtu/hr)	(lb/mmBtu)	(lb/hr)	(hr)	Type	(%)
Rawhide	101	operating	CO		PC	2001	0.23	8832	0.458	2001	285	285	3083	0.074	225	8760	LSD	83.8%
Comanche	3	application	CO		PC		0.29	8200	0.613		750	1850	7421	0.100	742	8760	LSD	83.7%
Navajo	2	operating	AZ		PC	2001	0.53	10909	0.923	2001	803	803	7837	0.035	270	8760	WLS	96.2%
Navajo	1	operating	AZ		PC	2000	0.53	10919	0.922	2000	803	803	7366	0.038	280	8760	WLS	95.8%
Navajo	2	operating	AZ		PC	2001	0.53	10909	0.923	2002	803	803	8116	0.039	281	8760	WLS	95.8%
Navajo	1	operating	AZ		PC	2001	0.53	10908	0.923	2001	803	803	6544	0.040	243	8760	WLS	95.7%
Navajo	1	operating	AZ		PC	2001	0.53	10909	0.923	2002	803	803	7843	0.040	299	8760	WLS	95.6%
Bonanza	1	operating	UT	2/04/81	PC	2001	0.40	9928	0.705	2002	400	400	5140	0.045	227	8760	WLS	93.6%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	9114	0.046	419	8760	WLS	94.0%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2000	0.48	11817	0.772	2000	820	820	9028	0.048	432	8760	WLS	83.8%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2002	820	820	8875	0.050	443	8760	WLS	93.9%
Clover	1									2001			4406	0.050	219	8760		94.0%
Navajo	3	operating	AZ		PC	2001	0.53	10909	0.923	2002	803	803	7917	0.050	370	8760	WLS	94.6%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2002	820	820	8768	0.050	438	8760	WLS	93.8%
Navajo	2	operating	AZ		PC	2000	0.53	10919	0.922	2000	803	803	7774	0.051	418	8760	WLS	94.5%
Navajo	3	operating	AZ		PC	2001	0.53	10909	0.923	2001	803	803	7501	0.053	396	8760	WLS	94.2%
STEAG-Desert Rock		application	NEPA		PC		0.82	8910	1.611		750	1500	13820	0.055	757	8760	WLS	0.0%
Intermountain Pwr	2	operating	UT	mid-80s	W-DB-PC	2001	0.51	11818	0.820	2001	820	820	9367	0.056	522	8760	WLS	93.2%
Bonanza	1	operating	UT	2/04/81	PC	2001	0.40	9929	0.705	2001	400	400	4846	0.057	278	8760	WLS	93.0%
Intermountain Pwr	1	operating	UT	mid-80s	W-DB-PC	2001	0.51	11819	0.820	2001	820	820	8378	0.058	487	8760	WLS	93.0%
Navajo	3	operating	AZ		PC	2000	0.53	10919	0.922	2000	803	803	8261	0.058	458	8760	WLS	93.7%
Clover	2									2001			4451	0.060	268	8760		92.6%
Clover	2									2002			4315	0.062	287	8760		92.2%
Bonanza	1	operating	UT	2/04/81	PC	2000	0.40	10008	0.699	2000	400	400	4641	0.063	293	8760	WLS	91.0%
Clover	1									2002			4254	0.064	272	8760		91.8%
Hunter (Emery)	3	operating	UT	1983	W-DB-PC	2000	0.45	11784	0.726	2000	495	498	4035	0.067	239	8760	WLS	92.5%
Hunter (Emery)	3	operating	UT	1983	W-DB-PC	2000	0.45	11784	0.726	2002	495	498	4032	0.084	340	8760	WLS	89.5%
Hunter (Emery)	3	operating	UT	1983	W-DB-PC	2000	0.45	11784	0.728	2001	495	498	3918	0.068	314	8760	WLS	89.7%
Colstrip	4	operating	MT	8/11/1979	T-PC	2000	0.75	8487	1.546	2001	778	778	7738	0.088	668	8760	WLS	95.5%
Harrison	3	operating	WV		DB-PC	1997	3.40	12553	5.146	1997	684	684		0.087		8760	WLS	98.3%
Yates	1									2002			711	0.089	63.2	8760		98.3%
Harrison	1	operating	WV		DB-PC	1997	3.40	12553	5.146	1997	684	684		0.090		8760	WLS	98.3%
Red Trail Energy		pending	ND		CFB		1.20	6900	3.043				250	0.090	23	8760	LSD	95.6%
Craig	3	operating	CO	?	DB-PC	2001	0.38	10181	0.653	2001	446	446	3912	0.090	353	8760	DL	89.5%
Harrison	2	operating	WV		DB-PC	1997	3.40	12553	5.146	1997	684	684		0.090		8760	WLS	98.2%
Craig	3	operating	CO	?	W-DB-PC	2001	0.38	10181	0.653	2002	446	446	3884	0.094	338	8760	DL	85.5%
Longview Power		issued	WV	03/01/04	PC		2.5	11750	4.043		600	600	6114	0.095	561	8760	WLS	97.8%
Conemaugh	2	operating	PA		PC	1997	2.22	12532	3.368	2002	936	936	7181.56	0.098	704	8760	WLS	88.0%
Colstrip	3	operating	MT	8/11/1979	T-PC	2000	0.75	8487	1.546	2002	778	778	7686	0.100	769	8760	WLS	93.6%
Deseret	2	pending	UT		CFB		1.00	4000	4.375		110	110	1478	0.100	148	8760	LSD	87.7%
Intermountain Pwr Project	3	issued	UT	10/15/04	W-DB-PC		0.75	11183	1.273		950		9050	0.100	805	8760	WLS	92.1%

* Actual emissions from existing sources or proposed or permitted limits for new sources

Table 6.a. NOx Rankings (1, 3 & 24-hr averaging periods)

NOx				Issue/Op	Boiler		Capacity			Emissions or Limits*			Period	Control	
Facility Name	Unit	Status	Permit #	Date	Type	Year	MW	Total	(mmBtu/hr)	(99Pct lb/mmBtu)	(lb/hr)	(Min 30-Day lb/mmBtu)	(hr)	Type	(%)
STEAG-Desert Rock		application	NEPA		PC	[redacted]	750	1500	13620	0.060	817	[redacted]	24	SCR	85%
Bull Mountain-Roundup		issued	MT	01/31/03	PC	2000	2x390	780	8026	0.070	562	[redacted]	24	LNB/SCR	80%
Intermountain Power Project	3	pending	UT		W-DB-PC	[redacted]	950	950	9050	0.07	634	[redacted]	24	LNB/SCR	84%
Longview Power		issued	WV	03/01/04	PC	[redacted]	600	600	6114	0.060	489	[redacted]	24	LNB/SCR	81%
Rocky Mtn Pwr-Hardin		issued	MT		PC	[redacted]	113	113	1304	0.080	117	[redacted]	1	SCR	
Rocky Mtn Pwr-Hardin		issued	MT		PC	[redacted]	113	113	1304	0.090	117	[redacted]	24	SCR	
Neil Simpson	II	operating	WY	1969	DB-PC	2002	100	100	319	0.097	31	[redacted]	24	LNB	77%
Bull Mountain-Roundup		issued	MT	01/31/03	PC	[redacted]	2x390	780	8026	0.100	803	[redacted]	1	LNB/SCR	71%
Greene Energy		pre-ap	PA		W-DB-PC	[redacted]	950	950	5612	0.100	551	[redacted]	3	SCR	69%
Greene Energy		pre-ap	PA		W-DB-PC		960	950	5512	0.100	561	[redacted]	24	SNCR	69%
NEVCO-Sevier		pending	UT		CFB	[redacted]	270	270	2532	0.100	253	[redacted]	24	CFB/SNCR	59%
Northhampton Gen. Co.		operating	PA-0134	04/14/95	FB				1150	0.100	115	[redacted]	24		
Red Trail Energy		pending	ND		CFB	[redacted]			250	0.100	25	[redacted]	24	CFB/SNCR	72%
Comanche	3	application	CO		PC		750	1950	7421	0.162	1200	[redacted]	24	SCR	63%

* Actual emissions from existing sources or proposed or permitted limits for new sources

Table 6.b. NOx Rankings (720-hr averaging periods)

NOx				Issue/Op	Boiler		Capacity			Emissions or Limits*			Period	Control	
Facility Name	Unit	Status	Permit #	Date	Type	Year	MW	Total	(mmBtu/hr)	(99Pct lb/mmBtu)	(lb/hr)	(Min 30-Day lb/mmBtu)	(hr)	Type	(%)
BHP		pre-ap	NEPA		PC	[redacted]	550	550	5111	0.000	0	[redacted]	720	LNB/SCR	100%
Mt. Storm	1	operating	WV	?	T-PC	2001	570	570	5374	0.000	0		720		100%
Northside	1	operating	FL			2002			2343	0.000	0		720		100%
STEAG-Desert Rock		application	NEPA		PC	[redacted]	750	1500	13620	0.060	617	[redacted]	24	SCR	85%
AES Warrior Run		issued	MD-0022	06/03/94	ACFB					0.070			720	SNCR	
Black Hills Pwr-Wygen2		appealed	WY	09/25/02	PC	[redacted]	500	500	5146	0.070	350	[redacted]	720	LNB/SCR	85%
Bull Mountain-Roundup		issued	MT	01/31/03	PC	[redacted]	2x390	780	8020	0.070	561.8	[redacted]	720	LNB/SCR	80%
Intermountain Power Project	3	pending	UT		W-DB-PC	[redacted]	950	950	9050	0.070	634	[redacted]	720	LNB/SCR	84%
Kentucky Mountain Power		issued	KY	05/04/01	CFB	[redacted]	2 x 250	500	5100	0.070	357	[redacted]	720	FB/SNCR	10%
Kentucky Western Power		.	KY		CFB	[redacted]	2 x 250	500	5100	0.070	357	[redacted]	720	FB/SNCR	
Longview Power		issued	WV	03/01/04	PC	[redacted]	600	600	6114	0.070	428	[redacted]	720	LNB/SCR	84%
Santee Cooper Cross 3&4		pending	SC		PC	[redacted]	2x600	1200	11400	0.070	798	[redacted]	720	SCR	80%
Neil Simpson	II	operating	WY	1969	DB-PC	2002	100	100	269	0.078	21		720	LNB	84%
Beech Hollow		pre-ap	PA		CFB	[redacted]	300	300	2650	0.080	212	[redacted]	720	CFB/SNCR	85%
Kansas City P&L-Hawthorne		operating	MO		PC		570	570	6300	0.080			720	LNB/SCR	82%
Mustang		pending	NM		PC		300	300	3192	0.080	255		720	SCR	86%
Thoroughbred		issued	KY	10/11/02	PC		2x750	1500	14892	0.080	1191		720	LNB/SCR	70%
Gascoyne		issued	ND		CFB		175	175	2112	0.090	190		720		80%
JEA Northside Repower		issued	FL-0178	7/14/1999	CFB		2x298	596	5528	0.080	498		720	FB/SNCR	
LG&E Trimble County		pre-ap	KY		PC	[redacted]	750	750	6705	0.080	603		720	LNB/SCR	76%
Rocky Mtn Pwr-Hardin		issued	MT		PC	[redacted]	113	113	1304	0.090	117	[redacted]	720	SCR	
Deseret	2	pending	UT		CFB	[redacted]	110	110	1478	0.100	148	[redacted]	720	CFB/SNCR	84%
Greene Energy		pre=ap	PA		W-DB-PC	[redacted]	950	950	5512	0.100	561	[redacted]	720	CFB/SNCR	69%
NEVCO-Sevier		pending	UT		CFB		270	270	2532	0.100	253		720	CFB/SNCR	59%
Northhampton Gen. Co.		operating	PA-0134	04/14/95	FB				1146	0.10			720		
Red Trail Energy		pending	ND		CFB	[redacted]			250	0.100	25	[redacted]	720	SNCR	72%
Red Trail Energy		pending	ND		CFB	[redacted]			250	0.100	25	[redacted]	720	CFB/SNCR	72%
Kentucky Eastern Power			KY		CFB	[redacted]	2 x 250	500	5100	0.125	319	[redacted]	720	FB/SNCR	40%
York County Energy Partners		issued	PA-0132		CFB		2500	2500		0.125			720		
Edison-Mission Energy		issued								0.150			720	SCR	
Encoal Corp. North Rochelle		issued	WY-0047	10/10/97	PC			3960		0.150			720	LNB/OFA+SCR	
Energy New Bedford Cogen.		issued	MA-0009		CFB		150	300	3342	0.150			720	SNCR	

Taunton Energy Center		Issued			FB			1604	1604	0.160			720		
Tuscon Electric Power-Springerville			AZ		PC		2 x 380			0.150			720		
Two Elk Gen. Part, Lim. Part.		Issued	WY-0039	02/27/88	PC	[redacted]		250		0.150		[redacted]	720	LNB/OFA+SCR	
Apache	1					2001			645	0.16	105		720		83%

* Actual emissions from existing sources or proposed or permited limits for new sources

Table 8.c. NOx Rankings (8760-hr averaging periods)

NOx				Issue/Op	Boiler		Capacity			Emissions or Limits*			Period	Control	
Facility Name	Unit	Status	Permit #	Date	Type	Year	MW	Total	(mmBtu/hr)	(99Pct lb/mmBtu)	(lb/hr)	(Min 30-Day lb/mmBtu)	(hr)	Type	(%)
Neil Simpson	II	operating	WY	1989	DB-PC	2002	100	100	265	0.055	14	[redacted]	8760		90%
STEAG-Desert Rock		application	NEPA		PC		750	1500	13820	0.056	767	[redacted]	8760	SCR	86%
BHP		pre-ap	NEPA		PC		550	550	5111	0.060	307	[redacted]	8760	LNB/SCR	89%
Northside	1	operating	FL			2002			1884	0.060	114	[redacted]	8760		90%
Longview Power		issued	WV	03/01/04	PC		600	600	6114	0.065	397	[redacted]	8760	LNB/SCR	85%
Northside	2	operating	FL			2002			1841	0.068	125	[redacted]	8760		90%
Black Hills Pwr-Wygen2		appealed	WY	09/25/02	PC		500	500	5146	0.070	360	[redacted]	8760	LNB/SCR	85%
Bull Mountain-Roundup		issued	MT	01/31/03	PC		2x390	780	7474	0.070	523	[redacted]	8760	LNB/SCR	80%
Intermountain Power Project	3	pre-ap	UT		W-DB-PC		950	950	9060	0.070	634	[redacted]	8760	LNB/SCR	84%
Santee Cooper Cross 3&4		pending	SC		PC		2x600	1200	11400	0.070	798	[redacted]	720	SCR	80%
Beech Hollow		pre-ap	PA		CFB		300	300	2650	0.080	212	[redacted]	8760	CFB/SNCR	85%
Mustang		pending	NM		PC		300	300	3192	0.080	255	[redacted]	8760	LNB/SCR	86%
Thoroughbred		issued	KY	10/11/02	PC		2x750	1500	14892	0.080	1191	[redacted]	8760	LNB/SCR	70%
LS Power-Plum Point Energy		pending	AR		PC		800	800	8358	0.090	1337	[redacted]	8760	LNB/SCR	81%
Prairie State Gen		pending	IL		PC		2x750	1500	14886	0.090	1340	[redacted]	8760	LNB/SCR	67%
Rocky Mtn Pwr-Hardin		issued	MT		PC		113	113	1304	0.090	117	[redacted]	8760	SCR	
N. Amer. Pwr-Mid PRB		dead	WY		PC		500	500	4664	0.091	424	[redacted]	8760	SCR	79%
Two Elk #2		dead	WY		PC		1 x 500	500	4664	0.091	424	[redacted]	8760	SCR	79%
Deseret	2	pending	UT		CFB		110	110	1478	0.096	142	[redacted]	8760	CFB/SNCR	85%
Comanche	3	application	CO		PC		750	1950	7421	0.10	742	[redacted]	8760	SCR	77%

* Actual emissions from existing sources or proposed or permited limits for new sources

Table 8.a.
Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only Fabric Filter for Emissions control

based on Comanche Unit #1 Max Allowable 24-hr Heat Input
assumes heating value of 8929 Btu/lb and a sulfur content of 0.40 % and an ash content of 4.60 %

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions (Bold values from Table 1.1-5.)															
PC-DB	0.0146	0.0046	0.0023	0.6	0.0023	0.0022	1	0.00009	10	0.010	0.008	SO4	3*f(RH)	0.002	SOA	4

Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions (Bold Values from Table 1.1-6.)															
PC-DB	0.291	0.092	0.046	0.6	0.046	0.044	1	0.0017	10	0.199	0.159	SO4	3*f(RH)	0.040	SOA	4

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions															
PC-DB	100%	32%	15.8%	0.6	15.8%	15.2%	1	0.6%	10	68%	54.7%	SO4	3*f(RH)	13.7%	SOA	4

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. 1	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions															
PC-DB	1561	500	250	0.6	250	241	1	9	10	1080	864	SO4	3*f(RH)	216	SOA	4

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Filterable)	Ext. Coef.	Fine (% of Filterable)	Fine Soil (% of Filterable)	Ext. 1	Fine EC (% of Filterable)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Condensible)	Particle Type	Particle Ext.Coef.	CPM OR (% of Condensible)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions															
PC-DB	100%	32%	50%	0.6	50.0%	48.2%	1	1.9%	10	68%	80%	SO4	3*f(RH)	20%	SOA	4
						(% of Fine)	Coef.	(% of Fine)	Coef.							
						96.3%	1	3.7%	10							

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	[illegible]	Fine (lb/hr)	[illegible]	[illegible]	[illegible]	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
	Controlled PM10 Emissions													
PC-DB	1561	500	[illegible]	250	[illegible]	[illegible]	[illegible]	1080	[illegible]	SO4	3*f(RH)	216	SOA	4

Table 8.b.
Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + Fabric Filter for Emissions control

based on Comancho Unit #2 Max Allowable 24-hr Heat Input
assumes heating value of 9929 Btu/lb and a sulfur content of 0.40 % and an ash content of 4.60 %

	Controlled PM10 Emissions (Bold values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Ext.Coef.
PC-DB	0.0245	0.0046	0.0023	0.6	0.0023	0.0022	1	0.00009	10	0.020	0.016	SO4	3*f(RH)	0.004	SOA	4

	Controlled PM10 Emissions (Bold Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Ext.Coef.	CPM OR (lb/ton)	Particle Type	Ext.Coef.
PC-DB	0.489	0.092	0.046	0.6	0.046	0.044	1	0.0017	10	0.397	0.318	SO4	3*f(RH)	0.079	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Ext.Coef.	CPM OR (% of Total)	Particle Type	Ext.Coef.
PC-DB	100%	19%	9.4%	0.6	9.4%	9.1%	1	0.3%	10	81%	65.0%	SO4	3*f(RH)	16.2%	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. 1	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Ext.Coef.	CPM OR (lb/hr)	Particle Type	Ext.Coef.
PC-DB	2325	437	219	0.6	219	211	1	8	10	1888	1510	SO4	3*f(RH)	378	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Filterable)	Ext. Coef.	Fine (% of Filterable)	Fine Soil (% of Filterable)	Ext. 1	Fine EC (% of Filterable)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Condensible)	Particle Type	Ext.Coef.	CPM OR (% of Condensible)	Particle Type	Ext.Coef.
PC-DB	100%	19%	50%	0.6	50.0%	48.2%	1	1.9%	10	81%	80%	SO4	3*f(RH)	20%	SOA	4
						(% of Fine)	Coef.	(% of Fine)	Coef.							
						96.3%	1	3.7%	10							

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	[illegible]		Fine (lb/hr)	[illegible]		[illegible]	[illegible]	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Ext.Coef.	CPM OR (lb/hr)	Particle Type	Ext.Coef.
PC-DB	2325	437	[illegible]		219	[illegible]		[illegible]	[illegible]	1888	1510	SO4	3*f(RH)	378	SOA	4

Table 6.c.
Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + Fabric Filter for Emissions control

based on Comancho Unit #3 Max Allowable 24-hr Heat Input
assumes heating value of 9929 Btu/lb and a sulfur content of 0.40 % and an ash content of 4.60 %

	Controlled PM10 Emissions (Bold values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0246	0.0046	0.0023	0.6	0.0023	0.0022	1	0.00009	10	0.020	0.016	SO4	3*f(RH)	0.004	SOA	4

	Controlled PM10 Emissions (Bold Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.489	0.092	0.046	0.6	0.046	0.044	1	0.0017	10	0.397	0.316	SO4	3*f(RH)	0.079	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	19%	9.4%	0.6	9.4%	9.1%	1	0.3%	10	81%	65.0%	SO4	3*f(RH)	16.2%	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. 1	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	142	27	13	0.6	13	13	1	0	10	115	92	SO4	3*f(RH)	23	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Filterable)	Ext. Coef.	Fine (% of Filterable)	Fine Soil (% of Filterable)	Ext. 1	Fine EC (% of Filterable)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Condensible)	Particle Type	Particle Ext.Coef.	CPM OR (% of Condensible)	Particle Type	Particle Ext.Coef.
PC-DB	100%	19%	50%	0.6	50.0%	48.2%	1	1.9%	10	81%	80%	SO4	3*f(RH)	20%	SOA	4
						(% of Fine)	Coef.	(% of Fine)	Coef.							
						96.3%	1	3.7%	10							

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	[illegible]	[illegible]	Fine (lb/hr)	[illegible]	[illegible]	Fine EC [illegible]	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	533	100	[illegible]	[illegible]	50	[illegible]	[illegible]	[illegible]	10	432	346	SO4	3*f(RH)	86	SOA	4

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